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No. 09-288

Supreme Court, U.S.
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In The
Supreme Court of the United States

PUGET SOUND ENERGY, INC., AVISTA CORPORATION, AVISTA ENERGY, INC., CONSTELLATION ENERGY COMMODITIES GROUP, INC., IDACORP ENERGY L.P., MORGAN STANLEY CAPITAL GROUP INC., PORTLAND GENERAL ELECTRIC COMPANY, POWEREX CORP., SEMPRA ENERGY TRADING LLC, SHELL ENERGY NORTH AMERICAN (US), L.P., AND TRANSCANADA ENERGY LTD.,

Petitioners,

v.

THE PEOPLE OF THE STATE OF CALIFORNIA EX REL. EDMUND G. BROWN JR., ATTORNEY GENERAL, THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA, THE CITY OF SEATTLE, WASHINGTON, THE PORT OF SEATTLE, WASHINGTON, AND THE CITY OF TACOMA, WASHINGTON,

Respondents.

On Petition For A Writ Of Certiorari To The United States Court Of Appeals For The Ninth Circuit

BRIEF IN OPPOSITION

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QUESTIONS PRESENTED

1. This Court ruled in *Heckler v. Chaney*, 470 U.S. 821, 838 (1985) that courts lack jurisdiction to review an agency's refusal to institute enforcement proceedings. When an agency "*does* act to enforce," however, its decision is reviewable. *Id.* at 832. The first question for review is:

Did the court of appeals lack jurisdiction under *Heckler* to review the decision of the Federal Energy Regulatory Commission ("FERC") to deny refunds to purchasers of electricity in the Pacific Northwest, where that decision was based on an administrative law judge's findings and recommendations after a contested evidentiary hearing?

2. Did the court of appeals err by ordering FERC to address evidence of market manipulation that FERC admitted into the record but failed to address in its decision?

3. After FERC interpreted an administrative complaint to exclude refunds for certain types of energy purchases, did the court of appeals err when, applying the same standard as the D.C. Circuit, the court rejected FERC's interpretation on the grounds that the face of the complaint demonstrated no intention to exclude such purchases and FERC's interpretation of the complaint was inconsistent with its prior interpretation of a closely-related complaint?

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BRIEF IN OPPOSITION

Respondents the City of Seattle, Washington ("Seattle"), the Port of Seattle, Washington ("Port"), the City of Tacoma, Washington ("Tacoma"), the People of the State of California ex rel. Edmund G. Brown Jr., Attorney General of the State of California (the "California Attorney General"), and the Public Utilities Commission of the State of California (the "CPUC") oppose the petition for a writ of certiorari to review the opinion of the Ninth Circuit Court of Appeals in this case.

INTRODUCTION

The Ninth Circuit Court of Appeals reviewed a FERC decision denying refunds for overcharges on wholesale electricity sales in the Pacific Northwest during the energy crisis of 2000-2001. The court reversed the decision on narrow fact-bound grounds and remanded it to FERC for further proceedings. The decision was correct and does not warrant review.

In *Heckler v. Chaney*, this Court held that an agency's refusal to institute enforcement proceedings is presumptively not subject to judicial review. The Ninth Circuit's decision does not conflict with *Heckler*, nor does it conflict with decisions of other circuit courts of appeals interpreting *Heckler*. FERC could have avoided judicial review by conducting whatever investigation it wished and making

whatever enforcement decision it wished, so long as it did not conduct an adjudicative proceeding. But FERC elected the latter course. After Puget Sound Energy, Inc. ("Puget") filed a complaint seeking relief from unreasonable electricity prices during the energy crisis, FERC allowed other Pacific Northwest purchasers to intervene and become parties, and then directed an administrative law judge ("ALJ") to conduct a public adjudicative proceeding to determine whether there were grounds to provide refunds for transactions in the Pacific Northwest (the "PNW Refund Proceeding"). The PNW Refund Proceeding involved discovery, the submission of extensive evidence, cross-examination, briefing, findings by an ALJ, oral arguments by the parties, and a decision by FERC to deny refunds. The court of appeals' review of this adjudicative decision did not in any way impair FERC's exercise of its separate discretionary enforcement authority.

Similarly, the Ninth Circuit's instruction that FERC address evidence of intentional market manipulation on remand did not improperly interfere with FERC's discretion to structure its own proceedings. Petitioners' argument rests on their incorrect factual assertion that FERC decided to address evidence of market manipulation and tariff violations occurring in the Pacific Northwest in separate seller-specific proceedings (the "Gaming & Partnership Proceedings"). But FERC specifically limited the Gaming & Partnership Proceedings to unlawful behavior in the

organized California markets and *excluded* the Pacific Northwest.

Nor does the court of appeals' decision conflict with the D.C. Circuit's deferential standard for reviewing agency decisions. The court of appeals rejected FERC's interpretation of the Puget complaint as excluding sales to the California Energy Resources Scheduling division of the California Department of Water Resources ("CERS") in the Pacific Northwest. The court cited with approval the D.C. Circuit's standard, and gave due deference to FERC. The court nevertheless was compelled to reject FERC's interpretation of the Puget complaint because that interpretation was inconsistent with the complaint's own words and directly contradicted FERC's interpretation of a closely-related energy crisis complaint involving sales in California markets.

Finally, the decision is interlocutory because the court of appeals remanded the case back to FERC, which may or may not ultimately award refunds.

In sum, the court of appeals applied settled law in a limited, fact-bound decision that was fully consistent with *Heckler* and in conformity with standard judicial practice in all circuit courts of appeals. The petition for certiorari should be denied.

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STATEMENT

The Federal Power Act ("FPA") provides that the business of selling electricity in interstate commerce "is affected with a public interest," and that federal regulation of such sales is "necessary in the public interest." FPA Section 201(a), 16 U.S.C. § 824(a). Rates charged for wholesale electricity by a public utility must be "just and reasonable." FPA Section 205(a), 16 U.S.C. § 824d(a). Whenever FERC, after a hearing on its own motion or in response to a complaint, finds that a rate is unjust and unreasonable, it is required to determine the just and reasonable rate and has discretion to order that refunds be paid. FPA Section 206(a) and (b), 16 U.S.C. § 824e(a) and (b). Complaints may be filed by any person, State, municipality or state commission. FPA Section 306, 16 U.S.C. § 825e. If FERC determines that a complaint has any reasonable basis, it must conduct either an internal investigation or a public hearing. FPA Sections 306, 307 and 308, 16 U.S.C. §§ 825e, 825f and 825g. Any aggrieved party may seek judicial review of an order issued by FERC. FPA Section 313, 16 U.S.C. § 825*l*.

1. In August 2000, San Diego Gas & Electric Company filed a complaint with FERC that initiated a proceeding (the "California Refund Proceeding") requesting that FERC order a cap on "prices at which sellers subject to its jurisdiction may bid energy or ancillary services into California's two large bulk-power markets – those operated by the PX and the ISO." Resp. App. 2.

In October 2000, Petitioner Puget filed a closely-related complaint with FERC, contending that "California and the Pacific Northwest are part of the substantially integrated wholesale power market of the Western Interconnection."[1] Resp. App. 37. Puget also contended that FERC would seriously disrupt and distort that integrated wholesale market if it established price caps in only one part of that market as requested by the San Diego complaint. *Id.* at 40. Accordingly, Puget requested that, if FERC decided to impose a price cap in response to the San Diego complaint, it should also impose the same or a lower price cap on wholesale energy prices in the Pacific Northwest. *Id.* at 39-41.

Contrary to Petitioners' representation that Puget "expressly disclaimed interest in refunds," Pet. 5, the Puget complaint specifically asked FERC to set a refund effective date "in accordance with Section 206 of the [FPA] . . . sixty . . . days after the date of filing of this Complaint" (the earliest possible date for obtaining refunds under the then-applicable version of FPA Section 206) if FERC decided to order refunds

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[1] "Western Interconnection," "West-wide," and "West" refer to the geographical area encompassed within the Western Electricity Coordinating Council. It extends from Canada to Mexico and includes all or portions of fourteen western United States, the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California.

"in response to this Complaint." Pet. App. 11a, Resp. App. 42, 44.[2]

Less than two months later, shortly after finding in the California Refund Proceeding that prices in the California spot markets operated by the PX and ISO were unjust and unreasonable, FERC dismissed the Puget complaint, asserting that a West-wide price cap was "impracticable." 93 FERC 61,294 at 62,019. Puget filed a request for rehearing.

2. On June 19, 2001, FERC issued an order setting price caps on spot market sales throughout the West, including the Pacific Northwest, based on its finding that "'the California market is integrated with those of other states in the [West].'" Pet. App. 12a, Resp. App 127. Contrary to its finding several months earlier when it dismissed the Puget complaint, FERC concluded that a West-wide price cap was not only practical but also necessary "to modify the existing market structure throughout the West to minimize the potential for market power abuse, and thus to protect against possible unjust and unreasonable rates." Resp. App. 61.

A few days later, claiming to be satisfied with the remedy provided by the June 19 order, Puget filed a motion to withdraw its complaint. *Id.* In response, Port, Tacoma, Seattle, and the Washington Attorney

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[2] The court of appeals specifically rejected the contention by Puget and other sellers that "Puget's complaint never requested refunds or the setting of a refund effective date." Pet. App. 25a.

General filed answers opposing the motion, explaining that a dismissal would prejudice other entities that relied on the Puget complaint. Pet. App. 12a-13a. Consistent with FERC procedure in adjudicative proceedings, FERC allowed these entities to intervene. *Id.*

3. On July 25, 2001, FERC issued an order in both the California Refund Proceeding and the PNW Refund Proceeding. With respect to the former, FERC "establish[ed] the scope of and methodology for calculating refunds related to transactions in [the California Refund Proceeding]" and "establish[ed] an evidentiary hearing proceeding in order to further develop the factual record in [the California Refund Proceeding] so that refunds may be calculated." Pet. App. 38a-39a. With respect to the latter, FERC established a separate evidentiary "proceeding before an [ALJ] to explore whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest from December 25, 2000 through June 20, 2001, and the calculation of any refunds associated with such charges." *Id.* at 39a. FERC invited parties to the California Refund Proceeding to participate in the PNW Refund Proceeding. *Id.* at 13a, 102a-103a.

An ALJ conducted pre-hearing conferences in the PNW Refund Proceeding and issued an order on August 23, 2001 listing the issues to be tried, including whether refunds for spot market sales in the Pacific Northwest are "lawful or appropriate" and the "extent of any potential refunds." Pet. App. 114a.

After allowing the parties to engage in discovery, the ALJ conducted a three-day adjudicative hearing during which the pre-filed initial and/or rebuttal testimony of over 40 witnesses was taken and subjected to cross-examination. *Id.* at 417a-419a.

On September 24, 2001, the ALJ issued her "Recommendations and Proposed Findings." Pet. App. 111a-377a. Contrary to the Commission's prior determinations that the Pacific Northwest is a component part of a larger, single, inextricably integrated market that includes California, *id.* at 12a, the ALJ did not find the Pacific Northwest market to be connected to the California market in any significant way. The ALJ found that the Pacific Northwest market was functional and competitive and that prices were just and reasonable. *Id.* at 13a-14a. Accordingly, the ALJ recommended that refunds be denied. *Id.* at 14a. The ALJ also recommended that the Puget complaint be dismissed and that Puget be allowed to withdraw its rehearing request. *Id.* at 371a.

On December 19, 2002, while FERC was considering the findings and recommendations of the ALJ, new evidence came to light regarding Enron's manipulation of the electricity markets. Pet. App. 14a. FERC reopened the evidentiary record in the PNW Refund Proceeding to allow the parties to conduct additional discovery and submit "additional evidence concerning potential refunds for spot market bilateral sales transactions in the Pacific Northwest for the period January 1, 2000 through June 20,

2001" – a more extensive refund period than the one requested in the Puget complaint. *Id.*; Resp. App. 154. FERC also indicated that it would review the new evidence itself rather than remand for findings by the ALJ. Resp. App. 161-62. On March 3, 2003, Seattle, Port, and Tacoma submitted voluminous evidence supporting refund claims in response to this order.

On June 25, 2003, FERC adopted the ALJ's recommendation to deny refunds without addressing the new evidence submitted at FERC's own invitation. FERC rejected the ALJ's recommendation to allow Puget to withdraw its complaint because to do so would be unfair to parties seeking refunds who had "reasonably relied on the Puget complaint, which raised similar issues, as an appropriate forum for addressing their overlapping claims." Pet. App. 388a. FERC declined to make any finding as to whether wholesale market prices in the Pacific Northwest were unjust and unreasonable, instead concluding that, even if prices were unjust and unreasonable, the balance of equities weighed against ordering refunds. *Id.* at 392a-401a. Finally, FERC followed the ALJ's recommendation to exclude from the PNW Refund Proceeding transactions involving electricity purchased in the Pacific Northwest for consumption in California. *Id.* at 432a.

Respondents timely filed requests for rehearing of the June 2003 order, which FERC denied.

4. Respondents subsequently petitioned the Ninth Circuit Court of Appeals for review.[3] On August 24, 2007, the court of appeals granted the petitions in part and denied them in part. As a preliminary matter, the court rejected FERC's argument that, under *Heckler v. Chaney*, it lacked jurisdiction to review FERC's decision to deny refunds. The court of appeals recognized that, under *Heckler*, courts lack jurisdiction to review "'an agency's decision not to prosecute or enforce[,]'" but observed that, "when 'an agency *does* act to enforce, that action itself provides a focus for judicial review.'" Pet. App. 17a-18a (quoting *Heckler*, 470 U.S. at 831-32). Following *Heckler*, the court of appeals concluded that, "where FERC has made a determination to adjudicate a dispute or take[s] steps toward enforcing a violation of the law, the outcome it chooses is subject to judicial review[.]" *Id.* at 18a. The court found that FERC had taken those steps in this case by allowing interested persons to intervene, holding hearings, and taking evidence to adjudicate the refund dispute between the parties, and that FERC's ensuing decision to deny refunds was therefore reviewable. *Id.* at 18a-19a.

After rejecting the procedural challenges raised by the sellers, the court of appeals determined that

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[3] Seattle, Port, Tacoma, the California Attorney General, and the CPUC each petitioned for review of FERC's decision to deny refunds. The California Attorney General and the CPUC also petitioned for review of FERC's decision to exclude transactions involving energy consumed in California.

FERC's decision to exclude sales to CERS from the PNW Refund Proceeding based on its interpretation of the Puget complaint and FERC's failure to consider or examine the evidence submitted pursuant to its December 2002 order were arbitrary, capricious, and an abuse of discretion.

The court of appeals ruled that FERC's interpretation of the Puget complaint to exclude purchases made by CERS was inconsistent with any rational reading of the complaint and directly contradicted FERC's prior interpretation of the closely-related complaint that initiated the California Refund Proceeding.[4] Pet. App. 31a-32a.

The court of appeals also ruled that, "despite a great deal of new evidence submitted to FERC in the spring of 2003," "FERC failed to take any of it into account, relying instead on the ALJ's factual findings from September 2001, which were made prior to the Enron revelations [of market manipulation]." Pet. App. 33a-34a. In light of evidence submitted in response to FERC's December 2002 order, the court observed that "FERC must at least consider the possibility that the [PNW] spot market was not . . . functional and competitive." *Id.* at 35a.

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[4] The court of appeals also found that FERC's decision that sales to CERS did not occur in the Pacific Northwest was not supported by substantial evidence. Pet. App. 31a. Petitioners have not sought review on that basis.

The court of appeals "decline[d] to reach the merits of FERC's ultimate decision to deny refunds," and remanded to FERC to further consider its refund decision in light of the newly submitted evidence and the court's related decisions, issued subsequent to FERC's final order in this case. Pet. App. 36a.

ARGUMENT

1. There is no circuit conflict regarding the court of appeals' application of *Heckler v. Chaney*.

a. In *Heckler*, this Court granted certiorari to decide whether an agency's decision "*not to exercise* its enforcement authority . . . may be judicially reviewed." 470 U.S. at 828. Petitioners were inmates sentenced to death by lethal injection who asked the Food and Drug Administration ("FDA") to take investigative and enforcement actions under the Food, Drug & Cosmetic Act to prevent the use of certain drugs for human execution. *Id.* at 824. The FDA declined to do so, stating it would not exercise its jurisdiction to interfere with the state criminal justice system. *Id.* at 824-25. This Court determined that the FDA's decision was nonreviewable. It stressed that the exception to reviewability "remains a narrow one," *id.* at 838 (citing *Citizens to Preserve Overton Park v. Volpe*, 401 U.S. 402 (1971)), but ruled that an agency's decision not to prosecute or enforce "should be presumed immune from judicial review[,]" *id.* at 832.

This Court explained that decisions not to enforce are generally unsuitable for review because "an agency decision not to enforce often involves a complicated balancing of a number of factors which are peculiarly within its expertise," such as where to allocate agency resources and whether an agency is likely to succeed in its enforcement action. *Heckler*, 470 U.S. at 831. This Court further noted that an agency's refusal to act does not implicate its coercive powers. *Id.* at 832. By the same token, it observed, "when an agency *does* act to enforce, the action itself provides a focus for judicial review, inasmuch as the agency must have exercised its power in some manner." *Id.* Finally, this Court analogized an agency's refusal to institute proceedings to a prosecutor's decision not to indict. *Id.*

In the absence of any adjudication or statutory guidelines for the agency to follow in exercising its enforcement powers, this Court concluded that the FDA's refusal to act on the inmates' request provided no basis for judicial review. *Heckler*, 470 U.S. at 837-38.

b. The court of appeals cited *Heckler* and faithfully applied it to the facts of this case. Pet. App. 17a-19a. There is, as discussed below, no circuit conflict. Petitioners simply dispute whether the court properly applied *Heckler* to the facts, an issue that does not warrant review.

Here, far from refusing to institute proceedings, or engaging only in pre-enforcement activities, FERC

adjudicated the claims before it. *See Heckler*, 470 U.S. at 832. While FERC may – and sometimes does – limit an inquiry to an investigation short of prosecution, that is not what it did here. As discussed above, FERC responded to the filing of the Puget complaint by holding a public hearing and taking evidence "to adjudicate a dispute between the parties as to whether refunds should be awarded." Pet. App. 18a-19a. FERC allowed interested parties (other Pacific Northwest purchasers and public agencies representing consumer interests) to intervene and directed the parties to participate in a public evidentiary proceeding to determine "whether there may have been unjust and unreasonable charges for" spot market sales in the Pacific Northwest.[5]

In the course of this adjudicative proceeding, the ALJ authorized discovery, received direct and/or rebuttal testimony from 40 witnesses and gave the parties the opportunity to cross-examine those witnesses. Pet. App. 417a. After the conclusion of the hearing and submission of post-hearing briefs, the ALJ issued proposed findings of fact and recommendations, and the parties were given the opportunity to file comments with FERC in response. Pet.

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[5] Indeed, under FERC's investigative regulations, "[t]here are no parties, as that term is used in adjudicative proceedings, in an investigation under this part and no person may intervene or participate as a matter of right in any investigation under this part." 18 C.F.R. § 1b.11; *see also Baltimore Gas & Elec. Co. v. FERC*, 252 F.3d 456, 458 (D.C. Cir. 2001) (according to FERC, "third parties have no right to participate in investigations").

App. 417a-418a. FERC then allowed the parties to supplement the record with additional evidence supporting refunds, including refunds for time periods not covered by the Puget complaint, and to submit evidence regarding manipulation of the energy markets by Enron and other sellers. Pet. App. 14a, 418a; Resp. App. 161-62. Finally, FERC reviewed the record, along with the ALJ's findings and recommendations, and, following oral argument before the full Commission, issued a written decision declining to order refunds. Pet. App. 379a.

Ignoring the adjudicative nature of the proceeding, Petitioners argue that FERC's decision to deny refunds is not reviewable because FERC did not "initiate a proceeding." Pet. 19-21 & n.5. This curious assertion is based on Petitioners' claim that FERC never set Puget's complaint for a hearing. *Id.* at 20 n.5. This is simply incorrect. A hearing was held, and the Commission itself recognized that the proceeding was adjudicative. *See* Pet. App. 418a n.15 (citing adjudicative statute). Indeed, in its decision following the hearing, FERC identified the PNW Refund Proceeding as the *only* proceeding in which Respondents' claims for relief could be adjudicated. FERC explicitly rejected the ALJ's recommendation that the Commission allow Puget to withdraw its complaint and dismiss the entire proceeding, stating that: "After allowing intervenors to pursue a preliminary hearing through the Puget complaint until now, it would be unfair to deny relief based on procedural issues and

leave them with no other forum to pursue their complaints." *Id.* at 388a.

FERC's November 2003 order denying Respondents' requests for rehearing further reflects its recognition that the proceeding was adjudicative under *Heckler*. The order responds at length to objections that the ALJ's accelerated procedural schedule prevented parties from fully presenting their refund case. It defends the procedures used, finding that they comported with due process on grounds that parties had the opportunity to engage in discovery, examine and cross-examine witnesses, and supplement the record following the hearing. Pet. App. 416a-419a. As this Court has repeatedly held, due process considerations arise only in adjudications, not investigative proceedings. *S.E.C. v. Jerry T. O'Brien, Inc.*, 467 U.S. 735, 742 (1984) (the Due Process Clause is not implicated in an administrative investigation) (citing *Hannah v. Larche*, 363 U.S. 420, 440-43 (1960)); *see Hannah*, 363 U.S. at 442-43 (no right to cross-examination in investigative proceedings). FERC's recognition of its due process obligations (whether or not it met them) confirms that it viewed the proceeding as adjudicative.

In sum, FERC did not merely investigate and decide not to pursue enforcement. Instead, FERC adjudicated claims for relief and rendered a decision on the merits. Section 313 of the FPA provides that such decisions are reviewable by courts of appeals. 16 U.S.C. § 825*l*. The court of appeals in this case did nothing more than engage in the normal judicial

review of an agency's adjudicative decision, as all courts of appeals regularly do. Pet. App. 19a, citing cases.[6]

c. The circuit court cases cited by Petitioners are not in conflict with the court of appeals' decision. Petitioners' observation that "[f]our circuits interpret *Heckler* to hold that agency non-enforcement decisions do not become reviewable simply because the agency has taken investigative or pre-enforcement steps to inform its decision," Pet. 13, is irrelevant because FERC did not limit itself to such steps here.

Petitioners cite cases holding that agency decisions to settle are presumptively unreviewable. Pet. 13-15 (citing *New York State Dep't of Law v. FCC*, 984 F.2d 1209, 1213-15 (D.C. Cir. 1993); *Baltimore Gas & Elec. Co. v. FERC*, 252 F.3d 456, 459-60 (D.C. Cir. 2001); *Ass'n of Irritated Residents v. EPA*, 494 F.3d 1027, 1035 (D.C. Cir. 2007)). These cases have no bearing here. This case does not involve a settlement or anything analogous to one.

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[6] In addition to the cases reviewing FERC decisions to grant or deny refunds that were cited by the court of appeals (*i.e.*, *Pub. Utils. Comm'n of Cal. v. FERC*, 462 F.3d 1027 (9th Cir. 2006); *Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006 (9th Cir. 2004); and *Consol. Edison Co. of N.Y., Inc. v. FERC*, 347 F.3d 964 (D.C. Cir. 2003)), *see Westar Energy, Inc. v. FERC*, 568 F.3d 985 (D.C. Cir. 2009); *La. Pub. Serv. Comm'n v. FERC*, 522 F.3d 378 (D.C. Cir. 2008); *Keyspan-Ravenswood, LLC v. FERC*, 474 F.3d 804 (D.C. Cir. 2007); *Constellation Energy Commodities Group, Inc. v. FERC*, 457 F.3d 14 (D.C. Cir. 2006).

Petitioners also cite cases in which an agency conducted an investigation but decided not to pursue enforcement. Pet. 15-17 (citing *Greer v. Chao*, 492 F.3d 962 (8th Cir. 2007), *Sierra Club v. Larson*, 882 F.2d 128 (4th Cir. 1989), and *Sherman v. Black*, 315 F. App'x 347 (2d Cir. 2009)). These cases too are irrelevant. Petitioners misstate the unremarkable holding in each case that agency decisions to terminate investigations without further enforcement are unreviewable by asserting that the agencies in question "launched 'investigation[s]' in which complaining parties participated and were given opportunities to respond." Pet. 17. However, apart from *Greer*, in which the complaining party sought reconsideration, 492 F.3d at 963, there is no indication in any of these cases that any party participated or was given an "opportunit[y] to respond" to the investigation. Certainly none of the cases entailed an adversary proceeding of the kind FERC conducted here. To the contrary, these cases involved standard internal agency investigations that led to nonreviewable decisions declining to enforce violations alleged by the complaining parties. The agencies in those cases did not, as FERC did here, allow numerous parties to intervene, allow extensive discovery, hold formal public hearings before an ALJ, take testimony from numerous witnesses, or issue a substantive decision after the submission of post-hearing briefs.

d. Amici Law Professors ("Amici") assert that the court of appeals' opinion will cause "hopeless confusion," Amici Br. 8, tending to (1) "discourage

agencies from devoting resources to careful decisions about enforcement" for fear of exposing their decisions to judicial review; and (2) inconvenience private parties, who will lack certainty whether a given agency decision is subject to judicial review. Amici Br. 10-12, 17-18.

The court of appeals' decision will not result in either outcome. Courts have been reviewing FERC's adjudicative decisions to deny refunds for years. Fn. 6, *supra*. Amici point to no evidence that this well-established practice has discouraged agencies from making careful decisions about enforcement, or that it has harmed private parties in any way. To the contrary, judicial review serves to improve the quality of agency decisions and to prevent abuses of agency discretion.

Amici also claim that the court of appeals' decision subjects agencies to judicial review whenever they take "*any steps*" toward enforcement of the law, including "accept[ing] delivery of a petition seeking a § 206 petition," "issu[ing] a press release expressing concern about conditions in the market," or "obtain[ing] information from regulated entities." Amici Br. 8-9. The court's decision suggests no such thing; Amici take the word "steps" out of context to argue that anything an agency does is potentially subject to review.

Contrary to Amici's misreading, the court of appeals made clear in its decision that: "When an agency *has instituted* proceedings, meaningful standards exist to review what the agency has done:

'when an agency *does* act to enforce, that action itself provides a focus for judicial review, inasmuch as the agency must have exercised its power in some manner.'" Pet. App. 18a (quoting *Heckler*, 470 U.S. at 832). "Accordingly," the court of appeals stated, "where FERC has made a determination *to adjudicate a dispute or take steps toward enforcing a violation* of the law, the outcome it chooses is subject to judicial review[.]" *Id.* (emphasis added). *See also id.* at 18a-19a ("[H]ere . . . FERC has held hearings and taken evidence to adjudicate a dispute between the parties as to whether refunds should be awarded. Although the steps FERC has taken do not require FERC to find that refunds are appropriate, FERC's decision regarding the propriety of awarding refunds is reviewable by this court.").[7]

When the word "steps" is read in context, there is no doubt about the opinion's meaning or its congruity with *Heckler*. Far from "undermining" *Heckler*, Amici Br. 3, the court of appeals' opinion follows it to hold that when, as here, FERC has instituted an adjudicative proceeding rather than conduct an internal investigation, both FERC and the affected parties

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[7] Moreover, unlike *Heckler*, which applies in situations where "there is no meaningful standard against which to judge an agency's decision," *Heckler*, 470 U.S. at 830, FERC's action here was taken in the context of a Section 206 complaint, and the FPA specifically establishes the standard for FERC's review – whether rates are unjust, unreasonable, unduly discriminatory or preferential. 16 U.S.C. § 824e(a).

should expect FERC's decision in that proceeding to be subject to judicial review.[8]

Finally, Amici suggest that FERC's decision to deny refunds is nonreviewable because it is based on equitable factors. Amici Br. 8-9. But FERC's refund decisions always involve equitable and policy factors. *See, e.g., Keyspan-Ravenswood*, 474 F.3d at 812-13; *Koch Gateway Pipeline Co. v. FERC*, 136 F.3d 810, 816 (D.C. Cir. 1998). That does not render them any less reviewable, or any less subject to reversal if lacking a rational basis. *Id.*

2. The court of appeals did not improperly interfere with FERC's discretion to structure its own administrative proceedings when it ordered FERC to consider evidence of market manipulation in the PNW Refund Proceeding.

Petitioners argue that the court of appeals' mandate to FERC to consider evidence of market manipulation on remand in the PNW Refund Proceeding, rather than in the Gaming & Partnership

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[8] FERC knows how to structure its proceedings to draw the line between an internal investigation and an adjudication. *See, e.g., PJM Interconnection, L.L.C., et al.*, 97 FERC ¶ 61,319 (2001) (FERC denied motions to intervene in investigation initiated by show cause order regarding allegations of affiliate abuse, noting that intervention not permitted as a matter of right in investigations). FERC obviously could have conducted an investigation here, but instead chose to invite interested persons to participate in an adjudicative proceeding.

Proceedings,[9] "interfered with FERC's ability to structure its own dockets." Pet. 28. This argument rests entirely on fundamental factual misstatements regarding the nature and scope of these proceedings, FERC's reasoning, and the court of appeals' determinations.

Petitioners assert that "FERC reasonably decided to investigate and remedy allegations of tariff violations in seller-specific proceedings . . . rather than in" the PNW Refund Proceeding. Pet. 27. Petitioners identify those separate proceedings as "new proceedings specifically to investigate and redress alleged market manipulation and tariff violations in both California *and the PNW*." *Id.* at 24 (emphasis added); *see also* Amici Br. 14 (referring to the "new proceedings specifically targeted at market manipulation in California and the Pacific Northwest").

Petitioners and Amici are incorrect. FERC specifically limited the scope of the Gaming & Partnership Proceedings to examination of "gaming and/or anomalous market behavior in violation of the California Independent System Operator Corporation's (ISO) and California Power Exchange's (PX) tariffs."[10]

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[9] The Gaming & Partnership Proceedings were initiated by two FERC orders issued on the same day that FERC terminated the PNW Refund Proceeding: *Am. Elec. Power Serv. Corp.*, 103 FERC ¶ 61,345 (2003) and *Enron Power Mktg., Inc.*, 103 FERC ¶ 61,346 (2003). *See* Pet. 24.

[10] 103 FERC at 62,328 (P1); *see also* 62,328 (P2) 62,341 (P70, P71), 62,342 (ordering paragraph (A)), 62,348 (P2, P3),

(Continued on following page)

In fact, when Port requested on rehearing that FERC examine evidence of manipulation in the Pacific Northwest in the Gaming & Partnership Proceedings, FERC *refused*.[11]

Accordingly, FERC's decision to exclude "gaming practices that manipulated . . . the Pacific Northwest region," *see* fn. 11, *supra*, directly contradicts Petitioners' assertion that FERC "reasonably decided" to investigate tariff violations and market manipulation evidence in the Pacific Northwest in the separate Gaming & Partnership Proceedings.

In addition, FERC's orders initiating the Gaming & Partnership Proceedings never indicated that these proceedings were created for the purpose of addressing the new manipulation evidence submitted in the PNW Refund Proceeding. Likewise, there is no basis in the record of the PNW Refund Proceeding for

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62,351 (P12), 62,357 (P45, P46), and 62,358 (ordering paragraph (B)).

[11] *Am. Elec. Power Serv. Corp., "Order Denying Rehearing,"* 106 FERC ¶ 61,020 at 61,061 (2004) ("Port of Seattle argues that the Partnership Gaming proceeding should have included a review of potential gaming practices that manipulated all of the Western Electricity Coordinating Council (WECC) electricity market, including the Pacific Northwest region. . . . We will deny rehearing; we will not broaden the scope of these proceedings."). FERC later permitted evidence involving Pacific Northwest manipulation in certain proceedings involving Enron, but otherwise maintained its approach to excluding from all other Gaming & Partnership Proceedings review of potential gaming practices in the Pacific Northwest, including those involving the Petitioners here.

Petitioners' assertion that FERC's rationale for declining to address market manipulation therein was that these issues would be addressed in the Gaming & Partnership Proceedings. FERC itself did not articulate any such rationale at the time.[12]

Petitioners also state incorrectly that the court of appeals "recognized that 'FERC already [was] addressing market manipulation in separate proceedings focusing on misconduct[.]'" Pet. 25 (citing Pet. App. 35a-36a). To the contrary, the court of appeals held that FERC "fail[ed] to rely on this reasoning below, *see Laclede Gas Co. [v. FERC]*, 997 F.2d [936,] 945 [D.C. Cir. 1993] (FERC order 'must stand or fall on the grounds articulated by the agency in that order')[.]" Pet. App. 35a.

Finally, Petitioners mischaracterize the court of appeals' decision by claiming that "the court did not review the reasons FERC gave" for denying refunds and "made no effort to explain how allegations of market manipulation, if proved, could alter FERC's balancing of equitable factors." Pet. 25. In fact, the court of appeals carefully explained that FERC's failure to consider and address relevant evidence of

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[12] Indeed, FERC had opportunities in both its November 10, 2003 and February 9, 2004 orders denying rehearing (*see* Pet. App. 409a-447a and 448a-453a), to make the alleged connection between the June 25, 2003 Gaming & Partnership Proceedings orders and the order terminating the PNW Refund Proceeding, but it did not do so. Rather, FERC first asserted this connection in its 2005 brief to the Ninth Circuit.

market manipulation (which conflicted with the ALJ's findings of a lawful, competitive and functional market in the Pacific Northwest) was arbitrary and capricious. Pet. App. 33a-36a.[13]

3. The court of appeals gave due deference to FERC's interpretation of the Puget complaint; its rejection of that interpretation is consistent with D.C. Circuit precedent and no circuit conflict exists.

a. The court of appeals found that nothing in the Puget complaint supported FERC's interpretation that CERS' purchases in the Pacific Northwest for ultimate consumption in California were outside the scope of the complaint, that FERC's interpretation directly contradicted its interpretation of a closely-related complaint, and that FERC's interpretation was therefore "arbitrary, capricious, and an abuse of discretion." Pet. App. 31a.

Petitioners argue that the decision creates a conflict with the D.C. Circuit's standard for deference to agency rulings in *Burlington Northern R.R. Co. v. ICC*, 985 F.2d 589, 594-95 (D.C. Cir. 1993), *Amerada Hess Pipeline Corp. v. FERC*, 117 F.3d 596, 604 (D.C. Cir. 1997) and related cases. Citing these cases, Petitioners argue that the D.C. Circuit "consistently defers to agencies' constructions of parties' pleadings, particularly when the pleading falls in an area in

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[13] In light of these facts, the cases cited by Petitioners for the proposition that an agency may address issues in separate proceedings are irrelevant.

which 'the Commission has greater technical expertise . . . than does the [c]ourt,'" but the court of appeals failed to do so here because it "declined to read Puget's complaint in its proper context," and rejected FERC's interpretation based "solely on two sentences from the complaint." Pet. 29-31.

Petitioners are incorrect. There is no circuit conflict. Relying on the very same D.C. Circuit precedents cited by Petitioners, the court of appeals expressly acknowledged that "we owe deference to FERC's interpretation of the scope of Puget's complaint." Pet. App. 31a.

Contrary to Petitioners' argument, the court of appeals' decision makes clear that the court did in fact search for a basis to defer to FERC's interpretation of the complaint read in its overall context but was forced to conclude that, "[o]n its face, Puget's complaint provides no indication of an intent to exclude refunds for energy purchased in the Pacific Northwest spot market for consumption outside the geographical area." Pet. App. 31a. Petitioners cannot plausibly claim that the court of appeals' reliance on the actual words of the complaint somehow ignored the complaint's overall context. As the decision clearly shows, the court of appeals took into consideration the context of the complaint in some detail, going so far as to include FERC's contradictory interpretation of the closely-related price-cap complaint filed in the California Refund Proceeding. There, FERC construed the scope of the complaint to include transactions in the California markets regardless of where

the energy was consumed. Pet. App. 32a. Unhappily for Petitioners, the court of appeals, again expressing its agreement with the D.C. Circuit, relied on *Koch Gateway Pipeline Co. v. FERC*, 136 F.3d 810, 815-16 (D.C. Cir. 1998) in concluding that "[w]here an agency treats similar situations differently without reasoned explanation, its decision will be vacated as arbitrary and capricious." Pet. App. 32a. *See also Nat'l Fuel Gas Supply Corp. v. FERC*, 811 F.2d 1563, 1571 (D.C. Cir. 1987) ("[i]f the agency's interpretation of a contract has vacillated, deference might give the agency license to act arbitrarily by making inconsistent decisions without justification," making deference in that instance "inappropriate").

Deference does not mean complete abdication of judicial review. The D.C. Circuit standard applied by the court of appeals recognizes that courts cannot blindly defer to agency decisions that lack a rational basis. As the D.C. Circuit stated in *Amerada Hess*, cited by both Petitioners and the court of appeals, "deference . . . does not mean abdication of careful and thorough judicial review. . . . We will not accept FERC's interpretation . . . unless it is 'amply supported, both factually and legally.'" *Amerada Hess*, 117 F.3d at 604 (citations omitted). Here, after conducting the "careful and thorough" review endorsed by the D.C. Circuit in *Amerada Hess*, the court of appeals was compelled to reverse FERC's decision, just as the D.C. Circuit has done in similar circumstances. *See, e.g., Idaho Power Co. v. FERC*, 312 F.3d 454, 461 (D.C. Cir. 2002) (recognizing deference due to FERC's

interpretation of ambiguous tariff language but vacating FERC's decision because FERC's interpretation of the tariff was contrary to prior interpretations and "nonsensical"); *Tesoro Alaska Petroleum Co. v. FERC*, 234 F.3d 1286, 1289-95 (D.C. Cir. 2000) (recognizing that deference due to FERC decision dismissing complaints on summary disposition "does not [ ] mean passive acceptance of irrational or unexplained decision making" and reversing, finding FERC's decision "unconvincing" and lacking a reasoned explanation).

The court of appeals has done nothing more here than follow long-established principles of appropriate judicial review. The claimed circuit conflict is illusory.

b. Petitioners also claim that the court of appeals' failure to give due deference to FERC's interpretation of the Puget complaint undercuts the rule against retroactive ratemaking. Pet. 32. The rule against retroactive ratemaking flows from Section 206 of the FPA and requires that rates may be revised by FERC only after application by the seller, or after a complaint has been filed against the seller, thus providing the seller notice that a transaction may be subject to refund. *Id.* at 33. The court of appeals did not disturb this concept. The court merely held, correctly, that the Puget complaint provided clear notice to sellers "that they may be liable for refunds for sales of energy in those markets, regardless of where the energy would be consumed." Pet. App. 32a.

4. Finally, the limited holding of the decision below and the interlocutory posture of the case provide additional reasons for denying further review.

The court of appeals declined to reach the merits of the refund dispute and remanded to the Commission to conduct further proceedings, including evidentiary hearings as needed, in light of intervening case law. This Court grants review of an interlocutory decision only in extraordinary circumstances, *American Construction Co. v. Jacksonville, Topeka & K.W.R. Co.*, 148 U.S. 372, 384 (1893), and avoids doing so when it will induce inconvenience, litigation costs, and delay in determining ultimate justice, *Gillespie v. U.S. Steel Corp.*, 379 U.S. 148, 152-53 (1964). Petitioners cite no extraordinary circumstances justifying review at this juncture, because none exist. Further review at this stage will only cause delay and harm Respondents, who have been waiting for final resolution of the refund dispute for close to a decade.

CONCLUSION

For the foregoing reasons, the petition for a writ of certiorari should be denied.

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company	)	
v.	)	
Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange[1]	)	**Docket No. EL00-95-000**

COMPLAINT

(Filed Aug. 2, 2000)

The design and structure of the markets conducted by the California Independent System Operator Corporation ("ISO") and the California Power Exchange Corporation ("PX") are fundamentally flawed and inherently incapable of producing workable competition to protect the interest of consumers. Therefore, pursuant to Rule 206 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206, San

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[1] As described more fully below, this complaint seeks amendment to the market-based rate schedules of all sellers into the markets for energy and ancillary services conducted by the California Independent System Operator and the California Power Exchange. Listing of all such sellers would be impracticable. Service of this complaint is described in footnote 22 below.

Diego Gas & Electric Company ("SDG&E") petitions the Commission for an emergency order capping at $250 per MWh the prices at which sellers subject to its jurisdiction may bid energy or ancillary services into California's two large bulk-power markets – those operated by the PX and the ISO.

The prices that now prevail in those markets do not reflect legitimate forces of supply and demand and, of themselves, belie any suggestion that the markets are workably competitive under peak demand conditions. To protect consumers in San Diego and elsewhere in California from these market failures, the Commission must intervene now.

I. INTRODUCTION AND SUMMARY

Since the beginning of June, wholesale electricity prices in California have shot up to levels that exceed, often by a multiple of three or four, prices seen at comparable load levels in prior years. The increase in prices has far outpaced the increase in fuel prices and greatly exceeds the cost of producing electricity. Quite simply, California wholesale markets are, particularly at high demand levels, dysfunctional, allowing sellers to exact prices considerably above levels that would prevail in open competition, where the demand side of the equation could participate in the market.

The impact of elevated wholesale prices has been felt statewide, as evidenced by the July 27 letter of Governor Davis to Chairman Hoecker attached as Appendix A. That impact has been particularly severe

in the San Diego area, where retail prices have been uncapped since June 1999.

Restructuring in California has, from the outset, followed a path markedly different from that followed elsewhere. The California structure is characterized, among other things, by separate responsibility for forward markets on the one hand and for real-time markets and transmission service on the other; by an imprecise zonal pricing system; and by retail rate caps that (outside the San Diego area) effectively prevent consumers from taking steps to curtail electric demand when prices are high. Operating within this structure, the ISO has increasingly resorted to inefficient and costly patchwork devices to maintain system reliability.

The Commission has made clear, with growing emphasis, that fundamental reform is needed. To date, the ISO has been less than fully responsive.

Sorting out issues of market design and structure will take time: certainly months, perhaps more. Consumers in California cannot wait that long. Nor can the ISO solve the immediate problem itself. Yesterday the ISO lowered the maximum price that it will pay for imbalance energy and ancillary services to $250 per MWh, but that cap does not apply to the larger PX markets. This Commission is charged with assuring that wholesale prices charged by jurisdictional sellers are just and reasonable. It must step in immediately to do so.

The only way that the Commission can rein in prices in bid-based markets such as those of the PX and ISO is to limit what sellers can bid. Specifically, the Commission should condition existing and future market-based rate authorizations to provide that the holder of the authorization may not submit bids to sell energy or ancillary services to or through the PX or ISO for more than $250 per MWh. That cap should remain in place while overhaul of the California markets proceeds, and until those markets are workably competitive.

II. BACKGROUND

SDG&E is a California corporation with its principal place of business at 8330 Century Park Court, San Diego, California 92123. SDG&E provides electric service to some 1.2 million customers in San Diego and Orange Counties, California.

The restructured California market began operation on April 1, 1998. Consistent with the orders of this Commission and the California Public Utilities Commission ("CPUC"), as well as state statute, the three large investor-owned utilities, Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("Edison"), and SDG&E transferred operational control of their respective transmission systems to the ISO, and began purchasing all of the energy needed to serve their retail customers through the PX. Each of the utilities also began providing its retail customers direct access to alternative suppliers.

and each has divested itself of all of its fossil-fueled generation in California. Each utility's retail rates were frozen by state statute for a transition period that was to continue until the utility had recovered certain stranded generation costs. SDG&E completed such recovery in June 1999, while neither PG&E nor Edison has yet done so. Thus, retail rate caps remain in place in their service territories, but not in SDG&E's. Unless remedied soon, the ISO and PX markets will produce the same adverse effects for Edison and PG&E's customers once those companies terminate the retail rate freeze.

III. CURRENT WHOLESALE PRICES IN CALIFORNIA FAR EXCEED ANY COMPETITIVE EQUILIBRIUM.

During the past two months, energy prices in the ISO-coordinated energy markets have started to behave erratically, producing prices that are three or four times the amounts for comparable time periods last year, and roughly doubling the monthly electric bills for SDG&E's customers.[2] The problem is both acute and chronic – unlike the "needle" peaks that roiled wholesale energy markets in the Midwest last year, prices in California energy markets are not retreating to their prior levels, and the difficulties

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[2] Appendix B hereto shows prices to SDG&E's residential customers, and the savings to such customers if a $250 price cap had been in effect this summer.

show no signs of abating. Significantly, the highest load on the California ISO grid this year (43,447 MW) is well below the peak level experienced during July of last year (45,574 MW). Yet, the market has routinely cleared at much higher prices during June and July of this year than during any month last year.

Appendix C hereto, comparing final PX day-ahead prices for the Southern California zone for the months of June and July during 1999 and 2000, respectively, provides a visual depiction of this marked change. During June and July of 1999, prices rarely exceeded $150/MWh even during the highest load levels. During the same period this year, prices have frequently exploded to three and four times the levels reached last year whenever load levels exceed 33,000 MW.[3]

To be sure, input fuel prices are twice the levels of last year and, as a result, even a perfectly working market would reflect some sustained price increase under these conditions. Natural gas prices at the southern California border during June and July of 1999 averaged about $2.30/MMBTU. During June and July of 2000, these prices have averaged about

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[3] Similarly in June and July 1999, the PX day-ahead price for Southern California never exceeded $250. In 2000, that price equaled or exceeded $250 167 times and $500 59 times. Appendix D shows the PX day-ahead price for each hour of June and July for each of the two years, together with the ISO-grid load for that hour.

$4.62/MMBTU. But the higher gas prices do not begin to explain the dramatically elevated prices that prevail in 2000 compared to 1999 when load levels exceed 33,000 MW. Translating the above fuel costs into delivered power prices for a typical Southern California gas-fired generating unit (10,000 BTU/kWh heat rate, volumetric gas transportation costs, fixed and variable O&M and a 65% capacity factor) results in a cost of $36/MWh in 1999, rising to $60/MWh in 2000. As the attached charts and tabular spreadsheets show, market clearing prices during June and July of 2000 have often exceeded the $60/MWh operating cost by an order of magnitude.

According to market monitoring reports, the total cost of energy charged to the California market for the month of June was nearly half of the total for all of 1999. Indeed, during one 10-day period in June, the cost charged to the market for ancillary services exceeded the total cost for all of 1999. During the entire month of June, the ISO spent $420 million to buy ancillary service capacity, whereas in June 1999 it spent just $35 million. Moreover, hour-to-hour price movements are inexplicable – capped $500/MWh imbalance energy prices are sometimes followed the next hour by $0/MWh prices. The hourly prices for ancillary services are also erratic, with lower-valued services sometimes clearing at prices that are higher than higher-valued services. In short, the design and structure problems inherent in the ISO's decentralized approach to market coordination is breaking down whenever the market is even moderately

stressed. These markets thus pose a clear threat to the economic and social well-being of California, its economy, and its citizens, especially in San Diego.

IV. BECAUSE THE DESIGN AND STRUCTURE OF THE CALIFORNIA ISO IS FUNDAMENTALLY FLAWED, A WORKABLY COMPETITIVE MARKET DOES NOT EXIST.

Restructuring of the electric industry has proceeded on the premise that competitive supply markets are both desirable and possible. It has long been recognized that the peculiar physical characteristics associated with electricity require that a structure be put in place that will establish "workably" competitive generation markets for the overall benefit of consumers. SDG&E believes in competition and believes that a workably competitive market for electricity is in the best interest of California and the nation, and will, if properly established, lead to lower prices. SDG&E has, however, understood from the beginning that the task of forming workably competitive markets is not easy and that the very best market structure and design concepts must be brought to bear to achieve the stated goals. SDG&E has stated publicly on many occasions its reservations about the structure adopted in California compared to other structures employed elsewhere in the nation.

Any weakness in the design of a market structure will quickly be exposed by market participants, even when engaged in wholly-permissible activities. This is what has happened in California. The only protection for consumers is a properly designed market that deals explicitly with the physics and externalities associated with a transmission network that is frequently congested and thus incapable of supporting all of the transactions that market participants prefer to execute.

According to the ISO, the design principles "that guided the California approach to restructuring . . . are captured most succinctly in two concepts: (1) full separation of competitive forward energy markets from monopoly transmission service, and (2) decentralized production decisions (unit commitment, dispatch, generation investment)."[4] The approach of the California ISO is unique in this regard, differing materially from the more centralized approach used by the PJM and New York ISOs, which attempts to preserve the well-known consumer benefits associated with an economically-efficient, least-cost dispatch.[5] Notwithstanding the California ISO's claims

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[4] *California ISO Congestion Management Reform Recommendation (Draft)*, July 11, 2000 at 15, hereinafter referred to as the *Reform Proposal*. The ISO report can be found at the California ISO's web site (http://www.caiso.com/clientservices/stakeholderprocesses/congestion management).

[5] The PJM and New York systems use an ISO-coordinated spot market based on a bid-based, security-constrained economic dispatch with nodal prices, financial transmission rights, and

(Continued on following page)

of having achieved a significant breakthrough in market design, the facts suggest that the California ISO – even after some 30 amendments to its tariffs – has failed to produce a market capable of supplying the electricity needs of California consumers at competitive prices.[6]

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the option of using either pool-based or physical bilateral schedules.

[6] SDG&E is not alone in concluding that wholesale markets in California are not workably competitive, at least at high load levels. The ISO Board explicitly so found in a resolution adopted on June 28, 2000. So too did Dr. Frank Wolak, Chairman of the ISO's Market Surveillance Committee ("MSC"), which is independent of ISO management. *See* Frank A. Wolak, "Recent Events in the California Electricity Industry and the Level of Price Caps on the ISO's Energy and Ancillary Service Markets" at 2. The report is available at http://www.caiso.com/docs/2000/07/06/200070615111266687.html. Defects in the markets have been catalogued by the MSC and by the PX's independent market monitoring organization in reports filed over the past two years. *See Report on Market Issues in the California Power Exchange Energy Markets*, filed in Docket Nos. ER 98-2843-001, *et al.* (Aug. 17, 1998); *Preliminary Report on the Operation of the Ancillary Services Markets of the California Independent System Operator*, filed in Docket Nos. ER98-2843-001, *et al.* (Aug. 19, 1998); *Second Report on Market Issues in the California Power Exchange Energy Markets*, filed in Docket Nos. ER98-2843-006, *et al. (March 10, 1999)*; *Report on Redesign of Markets for Ancillary Services and Real-Time Energy*, filed in Docket Nos. ER98-2843-007, *et al.* (April 6, 1999); *Annual Report on Market Issues and Performance*, filed in Docket No. ER99-3158-000 (June 4, 1999); *MSC's Report On Redesign of California Real-Time Energy and Ancillary Services Markets*, filed in Docket Nos. ER98-2843-000, *et al.* (Oct. 18, 1999); *PX Annual Report*, filed in Docket Nos. ER 96-1663 and EC 96-19 (July 30, 1999); *Third Report on Market Issues in the California Power Exchange*

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Difficulties with implementing the California ISO's novel approach to market coordination have been visible from the beginning, but most observers suspended judgment while the ISO struggled to implement its "de-centralized" approach to market coordination.[7] But instead of settling down and showing signs of maturity, the ISO-coordinated markets have increasingly required non-market "command and control" procedures to preserve short term reliability. Because the ISO does not have effective market-based procedures to keep the system in balance and maintain reliability – such as accurate locational pricing to support market-based congestion management; a well-structured day-ahead market to coordinate efficient unit commitment and a bid-based economic dispatch of the available generators; ancillary services markets properly designed and integrated with the day-ahead and balancing energy markets; and effective tools for mitigating locational market power – the ISO has been forced to develop jury rigged" solutions to countermand the perverse incentives produced by poor market design and structure. The resulting extra-market costs from

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Energy Markets, filed in Docket Nos. ER98-28843-000, *et al.* June 7, 2000).

[7] During much of the transitional start-up period, the ISO's prices were capped at $250/MWh – a number clearly higher than the running cost of any generator serving the California market but a comfort nevertheless for the utility distribution companies responsible for serving retail consumers at a commodity rate approximating one fifth of the wholesale cap.

these non-market solutions, of course, are passed on to consumers (more precisely, the utility distribution companies like SDG&E) through higher uplift payments.

Fortunately, the Commission eventually saw fit to intervene and question these practices, declaring the ISO's congestion management system to be fundamentally flawed and in need of overhaul or replacement, a finding that effectively touches on virtually every aspect of the California approach to market design.[8] The fate of other recent proposals and initiatives by the ISO illustrates that the California experiment in de-centralized market coordination is breaking down on a number of fronts. By the time the Commission found fundamental flaws in the ISO congestion management processes, it had already rejected the ISO tariffs governing generator interconnection. The Commission determined that the ISO-adopted procedures would undermine competition and discriminate against new entrant generators.[9] Shortly thereafter, the ISO withdrew the controversial long-term-grid-planning procedures that it had filed at the Commission. Belatedly, the ISO itself has come to concede that real problems exist, but it continues to argue that failures in

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[8] *California Independent System Operator Corp.*, 90 FERC ¶61,006 (January 7, 2000).

[9] *California Independent System Operator Corp.*, 88 FERC ¶ 61,221 (September 15, 1999); *reh'g denied*, 90 FERC ¶ 61,086 (January 31, 2000).

implementation rather than errors in the original market structure and design principles are the source of most of the difficulties.[10]

In some sense, these rejected and withdrawn proposals represent progress. The ISO's lawyers no longer need vigorously defend the ISO's implementation protocols, arguing that market separation, congestion management, and zonal pricing rules are functioning well and adequately police the ability of generators to exercise market power.[11] The Commission, of course, has now concluded otherwise, and directed the ISO to overhaul or replace its congestion management system and to review its market power mitigation practices. California consumers should not be expected to pay dramatically higher prices, however, while the ISO begins to confront and remedy the market power problems inherent in its de-centralized approach to market coordination.

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[10] *Reform Proposal* at 13.

[11] *See* the January 27, 2000, Answer of the California Independent Operator Corporation to Motions to Intervene and Reply Comments, criticizing the analysis and conclusions reached by Drs. Harvey and Hogan in *Nodal and Zonal Congestion Management and the Exercise of Market Power*, which had been submitted as part of Sempra Energy's comments on the ISO's *Report to the Federal Energy Regulatory Commission: Studies Pursuant to the October 30, 1997 Order*, Docket No. ER00-703-000. *See also* Drs. Harvey and Hogan's *Further Comment* attached to Sempra Energy's February 14, 2000, Answer, rebutting the ISO's claim that its zonal pricing system does not afford additional opportunities for exercising generator market power.

SDG&E does not, of course, believe that all of the current troubles can be laid solely at the feet of the California ISO and the poorly designed and structured wholesale markets that it coordinates. There are contributing factors not within the control of the ISO or this Commission that must also be addressed before the California market will work fully as intended. For instance, California needs more supply-side resources, both generation and transmission, to serve its growing load and to relieve significant transmission constraints. According to the California Energy Commission, 3,643 MW (five projects) will be under construction by the end of 2000, and 8,295 MW (14 projects) are under siting review.[12] Regulatory delay in siting new supply-side facilities must not be allowed to undermine the ability of the markets to function reliably. Conversely, just throwing more resources into the mix will not produce efficient results for consumers if the ISO's market-coordination procedures are dysfunctional and allow prices to remain well above competitive levels.

California's vision of industry restructuring also contemplated a vibrant retail market, where energy service providers would compete to manage price and supply risks for end-use customers. SDG&E fully supports California's decision to place the supply and price risk management function in the hands of

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[12] *See* http://www.energy.ca.gov/sitingcases/projects since 1979.

merchant companies with the skills and profit motive to execute this critically important function, but the retailing part of the restructured industry has not been able to make much headway, and few residential customers have left the "default" service provided by the utility distribution companies. Under California's restructuring polices, SDG&E has become an energy "delivery" company, but it will continue until directed otherwise to provide supply service for customers that have not yet chosen a supplier, by passing through the wholesale price in the PX and ISO markets. This is fine for consumers that are comfortable riding the spot market, but the volatility associated with even a workably competitive electricity market may not be acceptable for many consumers that would prefer to have some control over the price they will be charged for electricity. In addition to the *de facto* absence of market-based risk management for residential customers, California policy makers are grappling with the current inelasticity of demand (primarily because of the rate cap shielding Edison and PG&E's customers from the spot energy prices), and the lack of widespread deployment of hourly meters to allow customers to tailor their consumption patterns to market prices.

The resource siting and retail problems discussed above are all contributing to produce the unsatisfactory results facing SDG&E's customers. But the existence of these problems must not distract the Commission's attention from the basic inadequacy of the ISO/PX system – the ISO-coordinated wholesale

markets that are subject to the Commission's exclusive jurisdiction are dysfunctional, inefficient, and incapable of producing just and reasonable rates when loads reach moderately high levels. The Commission did not design this market, but its statutory responsibilities require that it lead the effort to fix the problems. The Commission must also take immediate, interim measures to protect consumers until reforms are in place and the Commission is able to certify that the design and structure of the California wholesale markets will produce workable competition.

V. THE ON-GOING STAKEHOLDER PROCESS TO REFORM THE ISO'S CONGESTION MANAGEMENT SYSTEM AND RELATED PROCESSES IS IMPORTANT AND NECESSARY, BUT COMES TOO LATE TO PROTECT CALIFORNIA CONSUMERS.

The Commission has extended substantial deference to the California ISO's unique approach to coordinating the short-term markets and has intervened to prompt reform only when it became clear that the ISO's Board of Governors was simply unable or unwilling to confront the underlying structure and design problems that now seem apparent to all.[13] The California markets will not

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[13] Unlike the other ISO's regulated by the Commission, most (but not all) of the members that sit on the California ISO's Board of Governors represent economic interests directly

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function consistently with the public interest until consumer welfare is placed at the top of the design list.

The Commission must insist that the California ISO market-coordination function be reformed to support efficient and effective competition. The mantra usually heard stakeholders want market separation, de-centralized decision making on dispatch and unit commitment issues, and suppression of locational pricing differentials – must not be allowed to stand in the way of a full examination of the reasons why the ISO/PX markets are not workably competitive. The ISO's July 11 *Reform Proposal*, which has been circulated to market participants for comment, on the one hand acknowledges that the current market-coordination practices are not working well, but, on the other hand, extols the virtues of the current market structure and design and steadfastly refuses to propose the changes that are necessary to support workable competition. Consequently, SDG&E is not optimistic that this Commission-initiated stakeholder reform effort will produce meaningful results without additional direction from the Commission.[14]

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affected by the ISO's market-coordinating tariffs and protocols, thus making it difficult to introduce reforms that could potentially disturb the existing economic and financial order.

[14] SDG&E is concerned that the ISO's *Reform Proposal* will not produce a workably competitive market, because the proposal would: 1) introduce more uncertainty and raise costs by

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SDG&E had hoped that the ISO's *Reform Proposal* would present a straightforward and compelling analysis of how the new approach would better mitigate market power and improve the performance of the market. SDG&E is particularly disappointed that the draft report does not explain why workable solutions being used elsewhere should not also be adopted in California. The draft *Reform Proposal* has not been able to shake free from the unique constraints that were incorporated in the original California design.[15] Rather than correcting

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pushing certain unit commitment decisions further forward in time (two day-ahead "reliability" market); 2) for certain units replace the two-settlement system of financial commitments with a specific performance requirement that would raise costs; 3) undermine a market-driven approach to transmission expansion; 4) undermine load management programs; 5) inflate costs in the two-day-ahead market when intra-zonal congestion is present; 6) continue to base inter-zonal real time operating decisions on a "simplified commercial model" rather than the actual network model; 7) increase complexity and uncertainty in using FTRs to hedge congestion costs; 8) likely subsidize wheeling transactions; 9) reduce the incentive for long term bilateral transactions between load and generation within constrained regions; 10) invite zonal price suppression and price discrimination; and 11) create poor procedures for creating new zones. These concerns, as well as a number of important ambiguities that remain unresolved, have been communicated to the ISO. We are prepared to work constructively with the ISO to develop alternative proposals to address these concerns and ambiguities, but so far the ISO-facilitated stakeholder process has, in our judgment, been ineffective in examining the efficacy of the original market design and structure that the ISO says must not be "abandoned." *Reform Proposal* at 13.

[15] For instance, preservation of the so-called "market separation rule," unique to California and flawed from first

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the rules for the existing markets along the lines that have worked elsewhere, the *Reform Proposal* pursues an approach requiring introduction of new markets and even more complicated procedures than currently in place. The new markets and rules are unfamiliar and unproven, and may well produce even more opportunities for "gaming" the system, leading to generally higher prices. It is clear that these most recent proposals are a step backward away from competitive markets and a step toward more intervention by the ISO to work around the special problems that have been created by its own rules. Given that there are well-designed market systems that have worked elsewhere, the burden should now be shifted to favor those working models and against the novel and distracting contortions of the *Reform Proposal* offered by the California ISO.

VI. UNTIL WORKABLE COMPETITION IS ESTABLISHED, SUPPLY BIDS INTO THE CALIFORNIA FORWARD AND REAL-TIME MARKETS SHOULD BE CAPPED AT $250 PER MWH.

As stated above, it is clear that the markets for energy and ancillary services in California are not workably competitive, at least when overall statewide demand reaches the neighborhood of 33,000

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principles, is cited as one of the main reasons why market power and related congestion problems cannot be dealt with in the normal real-time and day-ahead markets.

MW. At such demand levels, prevalent wholesale prices – prices subject to this Commission's jurisdiction – are neither just nor reasonable: suppliers are selling electricity at prices that far exceed prices produced by competition and, of course, consumers are being required to pay these prices and enrich the generators. SDG&E remains committed to the establishment of efficient, competitive electricity markets but, in the interim, the Commission must step in. Indeed, the question is not whether it should do so but how quickly. We submit that the Commission should act with urgency.

The necessary premise upon which sellers of energy or ancillary services have been authorized, under Section 205 of the Federal Power Act, to make sales at other than cost-based rates is that such sellers lack market power *and* that the markets into which they are selling are workably competitive. If markets are not workably competitive, the Commission cannot rely upon them, as an alternative to sellers' costs, to set just and reasonable rates.[16] As

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[16] *See Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1530 (D.C. Cir.), *cert. denied sub nom. Williams Pipe Line Co. v. Farmers Union Cent. Exch. Inc.*, 469 U.S. 1034 (1984); *see also Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 870-71 (D.C. Cir. 1993). The Commission requires applicants seeking market-based rate authority to show that – in combination with affiliates – they do not possess an unduly large share of the market for the relevant product in the relevant geographic area and cannot erect barriers to entry. *See Heartland Energy Services, Inc.*, 68 FERC ¶ 61,223 (1994); *Ocean Vista Power*

(Continued on following page)

shown above, the premise of workable competition does not hold true at present in the California PX and ISO energy and ancillary service markets, at least during high-load conditions.

In such circumstances, the authorization of suppliers to sell at rates exceeding cost – if continued at all – must, at the very least, be restricted. Specifically, the authorization of any seller to make sales for resale in interstate commerce at market-based rates should be conditioned to provide that, unless or until the Commission finds that bulk power markets for energy and ancillary services in California are workably competitive, such seller shall not submit a bid of more than $250 per MWh to supply energy or ancillary services into markets operated by the ISO or the PX.

SDG&E proposes a bid cap of $250 because that amount will easily exceed the variable costs of any supplier making sales into the ISO or PX markets, while still providing significant relief to consumers in high-load periods. Even the most inefficient gas-fired

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Generation, LLC, 82 FERC ¶ 61,114 (1998); *Cabrillo Power I LLC*, 86 FERC ¶ 61,180 (1999.)

The Commission has *not* required a showing that a particular market into which the applicant proposes to sell is itself workably competitive. Sellers who lack undue market share may receive prices that exceed competitive levels if they are participants in markets that, because of design flaws (or because other sellers do have unduly large shares) are not workably competitive.

generating unit should handily cover its operating costs at a $250/MWh price cap. At current natural gas prices (approximately $4.62 per MMBTU at the California border), operating costs for an inefficient gas-fired unit with a high heat rate of 20,000 BTU/kWh and a five percent capacity factor would be $147/MWh. Thus, virtually any gas-fired unit in the WSCC should be able to cover its operating costs under the $250 cap and earn some return of sunk capital costs.

As the Commission may be aware, on August 1, 2000, the ISO's Board of Governors voted to lower the ISO's purchase price cap to $250. That measure does not obviate the urgent need for Commission action. For one thing, of course, it can be reversed in the event that a relatively small number of Board members change their position – California ISO governors understandably reflect the perspectives of the particular interests they represent. More importantly, however, the ISO's price caps do not extend to transactions in the day-ahead, hour-ahead, and block forward markets conducted by the PX, which together account for the great bulk of the sales at wholesale to meet retail demand in California. In June 2000, for example, the amount of energy sold through the PX day-ahead and hour ahead energy markets together accounted for approximately four times the amount sold through the ISO real-time market. While caps on what the ISO pays for energy and ancillary services will have some effect on prices in the PX markets, that effect is indirect. Indeed, to the extent that the

ISO price caps influence PX prices, it is largely because demand will tend to migrate to the capped real-time energy market. As the ISO has emphasized, however, an increase in the portion of demand that is met in the real-time market also increases overall price volatility and makes the system less efficient to operate.[17]

Thus, a cap on the ISO's purchase price will not solve the problem at hand.[18] In contrast, a restriction on suppliers' authority to make sales at market-based rates would be directed at the proper party from a statutory perspective – the seller – and would provide broader protection against the exercise of market power and other market distortions. In short, even if the Commission could delegate to the ISO its responsibility to assure that wholesale rates charged by jurisdictional sellers are just and reasonable, such delegation would not be sufficient here.

The imposition of bid caps is not, of course, a long-term solution. The California electricity market must, as described above, be fundamentally reformed.

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[17] *See, e.g.*, the ISO's transmittal letter of January 28, 2000, in Docket No. ER00-1365-000 at 2 ("[T]he ISO most efficiently and effectively operates the ISO Controlled Grid when decisions on scheduling and commitment of resources are made through the Day-Ahead and Hour-Ahead Schedules.")

[18] The Commission has, of course, already concluded that it lacks the authority to compel the ISO to adopt a particular purchase price cap. *Morgan Stanley Capital Group Inc., v. California Independent System Operator Corp.*, Docket No., EL00-9[illegible]-000 (July 28, 2000).

The ISO's market-coordination practices must be altered to mitigate market power and improve overall efficiency; additional generation and transmission assets must be brought to bear; and the retail markets must be reformed to introduce market-based risk management and demand responsiveness. SDG&E, with its parent Sempra Energy, intends to play an active and constructive role in developing these solutions.[19] As such reforms take effect, the continued need for bid caps will need to be reassessed.[20]

VII. THIS COMPLAINT SHOULD BE PROCESSED AS QUICKLY AS POSSIBLE.

As described above, failure of bulk power markets at high-load levels is resulting, each day, in enormous transfers of wealth from captive buyers to

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[19] SDG&E welcomes the Commission's July 26, 2000, announcement that its staff will investigate the operation of bulk power markets and report its findings by November 1. California surely must be one of the primary subjects of that study. Again, however, Commission action to address the urgent circumstances described above cannot await completion of the investigation.

[20] In that regard, SDG&E hopes that conditioning the market-based pricing authority for bidders into the California PX and ISO markets will motivate suppliers to work for quick and effective market reformation so that their unfettered market-based pricing authority can be restored as promptly as possible.

generators and marketers selling through the PX and to the ISO. The need for action is genuinely urgent.

The Commission has indicated that its "Fast Track" procedures under 18 C.F.R. § 385.206(h) will not apply where the complaint seeks a change in a tariff.[21] For that reason, and because of the large number of suppliers whose market-based rate schedules are at issue, Fast Track procedures may not properly be applicable here.

On the other hand, given the urgency of the situation, time is of the essence. Accordingly, SDG&E respectfully requests that the Commission place the instant complaint on public notice as quickly as possible, and the fix time for filing answers at 15 days from the date of that notice.[22] Further, SDG&E

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[21] *Amoco Trading Corp. v. El Paso Natural Gas Co.*, 89 FERC ¶ 61, 165 (1999).

[22] SDG&E has served the instant complaint by overnight delivery or e-mail on all parties to the proceedings in which the ISO's purchase price caps have been at issue, to date, *i.e.*, Docket Nos. ER98-2843, ER99-4462, and EL00-91. It has also served the complaint on parties not included on any of those lists who are on the service list in the generic California restructuring proceedings, Docket Nos. ER96-1663 and EC96-19. Finally, SDG&E has provided this complaint in electronic form to the ISO, with a request that the ISO distribute it electronically to each entity on the ISO's list of market participants. SDG&E is also posting the complaint on its website in anticipation that its availability there will be cited in the Commission's notice of filing. SDG&E requests that, if the foregoing is not deemed to constitute substantial compliance with the requirements of Section 385.206(c), such requirements be waived.

respectfully urges the Commission to act as quickly as possible on the merits of this complaint.[23]

VIII. CONCLUSION

SDG&E respectfully requests that the Commission find that rates in excess of $250 per MWh for sales into the markets for energy and ancillary services operated by the California Independent System Operator Corporation and the California Power Exchange Corporation are unjust and unreasonable and that it condition the authorization to make sales into those markets at market-based rates accordingly. SDG&E further respectfully requests that the Commission act on this complaint at the earliest possible time.

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[23] Appendix E hereto is a notice of filing and is also submitted in diskette form, in accordance with Rule 206(b)(10). In accordance with Rule 206(b)(9), SDG&E states that none of the dispute resolution mechanisms listed therein has been used and, given the nature as well as the urgency of the issue, SDG&E does not believe that ADR under the Commission's supervision is practicable.

Respectfully submitted,

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August 2, 2000

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc. Complainant, v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement, Respondents.	)	Docket No. EL01-10-000

COMPLAINT OF PUGET SOUND ENERGY, INC.

(Filed Oct. 26, 2000)

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October 26, 2000

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PUGET SOUND ENERGY, INC. **v.** **ALL JURISDICTIONAL SELLERS OF ENERGY AND/OR CAPACITY AT COMPLAINT OF PUGET WHOLESALE INTO ELECTRIC ENERGY AND/OR CAPACITY MARKETS IN THE PACIFIC NORTHWEST, INCLUDING PARTIES TO THE WESTERN SYSTEMS POWER POOL AGREEMENT**[1]	**Docket No. EL01-10-000** **COMPLAINT OF PUGET SOUND ENERGY, INC.**

[1] As discussed further below, this Complaint seeks an order affecting the market-based rate schedules of wholesale sellers of energy and/or capacity into electric energy and/or capacity markets in the Pacific Northwest, including parties to the Western Systems Power Pool Agreement. Listing all such sellers in this caption would be impracticable. PSE is serving this Complaint on all parties to the Western Systems Power Pool (as listed on the Western Systems Power Pool website, www.wspp.org) as well as providing an electronic copy of this Complaint to the Western Systems Power Pool with a request that it distribute the copy electronically to each party to the Western Systems Power Pool Agreement. PSE is also requesting that Western Systems Power Pool post the Complaint on its website. PSE requests that if its actiions as described above are not deemed to constitute substantiall compliance with the requirements of Rules 203(a)(5) and 206(c), the Commission waive such requirements in this case.

Pursuant to Rule 206 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206, Puget Sound Energy, Inc. ("PSE"), hereby petitions the Commission for an order capping the prices at which sellers subject to Commission jurisdiction, including sellers of energy or capacity under the Western Systems Power Pool Agreement ("WSPP Agreement"), may sell capacity or energy into the Pacific Northwest's[2] wholesale power markets. PSE seeks an order that prospectively caps the prices for wholesale sales of energy or capacity into the Pacific Northwest at a level equal to the lowest cap on prices established, ordered, or permitted by the Commission for wholesale purchases in, or wholesale sales of energy or capacity to or through markets operated by, the California Independent System Operator Corporation (the "Cal ISO") or the California Power Exchange Corporation (the "Cal PX").

In support of its Complaint, PSE states the following:

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[2] As used in this Complaint, "Pacific Northwest" has the meaning set forth in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. sec. 839a(14).

I. NAME AND IDENTITY OF COMPLAINANT

1. The exact name and address of PSE is:

Puget Sound Energy, Inc.
411 – 108th Avenue, N.E.
P.O. Box 97034
Bellevue, Washington 98004-5028

All correspondence, communications, and pleadings in this proceeding should be sent to:

William A. Gaines
Vice President, Energy Supply
Puget Sound Energy, Inc.
411 – 108th Avenue NE, Suite 1500
Bellevue, Washington 98004
(425) 462-3145

It is respectfully requested that copies of all correspondence, communications, and pleadings in this proceeding be sent to:

William R. Maurer
Perkins Coie LLP
411 – 108th Avenue NE, Suite 1800
Bellevue, Washington 98004
(425) 453-6980

2. PSE is a corporation created and organized under the laws of the State of Washington, with its principal offices located in Bellevue, Washington. PSE is an electric and natural gas investor-owned utility engaged in, among other things, generating, transmitting, and marketing electric power in the West. PSE's wholesale power sales and interstate transmission of electricity are subject to the jurisdiction of

the Commission. PSE's retail service is subject to the jurisdiction of the Washington Utilities and Transportation Commission.

II. FACTS SUPPORTING THE COMPLAINT

A. Background

3. PSE sells power at market-based rates into, and buys power at market-based rates from, markets operated or directly affected by the Cal ISO and the Cal PX. For example, PSE makes sales at market-based rates into, and buys power at market-based rates from, the markets in the Pacific Northwest, which are directly affected by the Cal ISO and the Cal PX. PSE makes such power sales pursuant to or under authority of its market-based power sales rate schedule, which the Commission accepted for filing in *Puget Sound Energy, Inc.*, 86 F.E.R.C. ¶ 61,088 (1999).

3. PSE is a party to the WSPP Agreement. The WSPP Agreement has more than 220 parties, including over 97 power marketers, 53 investor-owned utilities (plus subsidiaries), 74 public entities, and one independent power producer. The WSPP Agreement sets forth terms under which parties enter into transactions to purchase and sell energy and capacity at rates that are often market-based rates. *See* Service Schedule C of the WSPP Agreement, WSPP's Rate Schedule FERC No. 6. Thousands of energy and capacity transactions take place each month by entities subject to the Commission's jurisdiction within

and between, among other places, California and the Pacific Northwest.

5. On August 2, 2000, San Diego Gas & Electric Company ("SDG&E") filed a Complaint (the "SDG&E Complaint") in Docket No. ELOO-95-000. The SDG&E Complaint alleged, among other things, that the "design and structure of the markets conducted by the [Cal ISO] and the [Cal PX] are fundamentally flawed and inherently incapable of producing workable competition to protect the interests of consumers." SDG&E Complaint at 1. The SDG&E Complaint called upon the Commission to take immediate action to limit bids into the Cal ISO and the Cal PX in an effort to stabilize prices for energy and ancillary services at the wholesale level.

6. In its Complaint, SDG&E sought an order "capping at $250 per MWh the prices at which sellers subject to [the Commission's] jurisdiction may bid energy or ancillary services into California's two large bulk-power markets – those operated by the PX and the ISO." SDG&E Complaint at 1. SDG&E's Complaint sought relief against all entities subject to this Commission's jurisdiction for whom the Commission has approved the sale of power at market-based rates.

7. The Commission has declined to institute the relief requested by SDG&E. Instead, the Commission has instituted, pursuant to section 206 of the Federal Power Act, a formal investigation to examine "the justness and reasonableness of the rates and charges

of public utilities that sell energy and ancillary services to or through the California ISO and PX, and to also investigate whether the tariffs and institutional structures and bylaws of the California ISO and PX are adversely affecting the efficient operation of competitive wholesale electric power markets in California and need to be modified." *Order Initiating Hearing Proceedings to Investigate Justness and Reasonableness of Rates of Public Utility Sellers in California ISO and PX Markets and to Investigate ISO and PX Tariffs, Contracts, Institutional Structures and Bylaws; and Providing Further Guidance to California Entities,* 92 F.E.R.C. ¶ 61,172, at 61,603 (Aug. 23, 2000).

8. Moreover, as noted by SDG&E in its Complaint, the Commission has permitted the Cal ISO to institute a price cap on its purchases of imbalance energy and ancillary services. In the order resulting from the SDG&E Complaint, the Commission described the Cal ISO purchase price cap:

> Although we have concluded that immediate seller price caps have not been justified based on the existing record, we have not disturbed the actions taken by the California ISO, in its discretion as a purchaser of imbalance energy and ancillary services, to set its purchase price cap at $250/MWh. This action addresses SDG&E's concern that pricing volatility be mitigated. While the ISO's authority to implement this cap expires in November 2000, the ISO has recently stated that it will make a timely

> filing with the Commission to extend its authority. *In addition, while only the ISO's markets are directly affected by its recent action, the ISO purchase price caps currently permitted by the Commission will serve to discipline prices in both the ISO and PX.* We disagree with SDG&E that the effect of the maximum purchase price that the ISO will pay for energy and ancillary services on prices in the PX market is only indirect.

Order Initiating Hearing, 92 F.E.R.C. at 61,606 (emphasis added); *see also Morgan Stanley Capital Group, Inc. v. Cal. Indep. Sys. Operator Corp.*, 92 F.E.R.C. ¶ 61,112 (July 28, 2000). Thus, the Commission has concluded that the existing Cal ISO purchase price cap "effectively disciplines prices in the PX markets." *Order Initiating Hearing*, 92 F.E.R.C. at 61,606. Any price cap on sales into the Cal PX or the Cal ISO would therefore expand the effect of an already existing price cap that the Commission has determined is affecting the Cal ISO and Cal PX markets.

9. On October 6, 2000, the California Municipal Utilities Association (the "Cal Munis") filed a Complaint, Request to Institute Cost-Based Rates and Motion to Consolidate (the "Cal Muni Request"). The Cal Munis sought an order from the Commission requiring "all jurisdictional sellers into the California ISO and PX markets to tender cost-based filings." Cal Muni Request at 27. The effect of such cost-based filings would be to establish a price cap on jurisdictional sales into those markets equal to the cost of service. In seeking such cost-based rates, the Cal Munis

argued that "California consumers are experiencing unprecedented, high, sustained wholesale power prices. Further, there is no end in sight, because needed investment in generation and transmission is years away." Cal Muni Request at 2. The Cal Munis also seek to consolidate their Request (Docket No. EL01-1-000) with, among other proceedings, the SDG&E docket (EL00-95-000) and the Commission's Section 206 investigation into pricing issues (EL00-98-000).

10. On October 16, 2000, Pacific Gas & Electric Company, the Southern California Edison Company, and the Utility Reform Network (the "Joint Movants") filed with the Commission a Joint Motion for Emergency Relief and Further Proceedings (the "Joint Motion"). The Joint Motion requests the Commission to, among other things, immediately impose a (interim) $100/MWh cap to apply to energy, ancillary services, and out-of-market dispatch calls in the Cal ISO and the Cal PX day-ahead, hour-ahead, day-of, and real-time markets. Joint Motion at 11. The Joint Movants allege that the "failure of California's wholesale electricity markets to produce just and reasonable prices has imposed enormous costs on the citizens and businesses of California and threatens the economic health of the entire State." Joint Motion at 3.

B. The California and Pacific Northwest Markets Are Part of the Substantially Integrated Market in the Western United States

11. California and the Pacific Northwest are part of the substantially integrated wholesale power market of the Western Interconnection, a large and complex bulk electric market serving customers throughout the Western United States, Canada, and a part of Mexico. See Prepared Testimony of Chairman James J. Hoecker, Federal Energy Regulatory Commission, before the Subcommittee on Energy Research, Development, Production and Regulation, Committee on Energy and Natural Resources, United States Senate, at p. 6 (Oct. 5, 2000) (hereinafter, "Testimony"). The Western Interconnection comprises the area in which members of the Western Systems Coordinating Council operate synchronously connected transmission systems. The Western Interconnection is one of three major interconnections in the United States and operates largely independently from the other two. The market conditions in California influence market conditions in the Pacific Northwest. *See* Testimony at 9 ("Given the highly integrated nature of the Western electrical systems, it is fair to ask the extent to which circumstances in California this summer affected wholesale prices in the Northwest."). Attachment A to this Complaint[3]

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[3] Appendix A is Attachment D to the Prepared Testimony of Stephen R. Oliver, Vice President, Bulk Marketing and

(Continued on following page)

shows historical On-Peak Spot Prices from January 1996 to September 2000. Attachment A includes, among other indices, the index of California electricity prices for the Cal PX and the Dow Jones Mid C Index[4] for the period from May 1998 to January 2000 and demonstrates a high degree of correlation between these two indices.

12. Similarly, the Prepared Testimony of BPA's Vice President, Bulk Marketing and Transmission Services, Power Business Line, before the same Subcommittee stated:

> The Pacific Northwest and California have always been significant trading partners. The two markets are connected by 7,900 MW of electric transmission interties. With open access to transmission systems, *the west coast market typically acts as one large marketplace, and Pacific Northwest electricity prices track closely with the prices in California.* . . . Therefore, the Pacific Northwest is significantly influenced by the market structure in California.

Transmission Services, Power Business Line, Bonneville Power Administration, United States Department of Energy, before the Senate Energy and Natural Resources Subcommittee and Energy Research, Development, Production and Regulation, Hearing on Northwest Energy Prices (Oct. 5, 2000).

[4] The Dow Jones Mid C Index is the weighted average price of electricity traded at Mid-Columbia, a primary trading hub, for electricity in the Pacific Northwest.

Prepared Testimony of Stephen R. Oliver, Vice President, Bulk Marketing and Transmission Services, Power Business Line, Bonneville Power Administration, United States Department of Energy, before the Senate Energy and Natural Resources Subcommittee on Energy Research, Development, Production and Regulation, Hearing on Northwest Electricity Prices, at 4-5 (October 5, 2000) (emphasis added).

13. Within the Western Interconnection, the Pacific Northwest and California are interconnected by the California-Oregon Intertie (the "COI"). This interconnection consists of several large transmission lines. Reflecting seasonal diversity in electrical load on the West Coast (i.e., high summertime loads in California due to air conditioning and high wintertime loads in the Pacific Northwest due to heating loads), power predominantly flows in seasonal directions on the COI, south in the summer and north in the winter. *See* Testimony at 6 ("During summer, when demand is high in California and water is typically available, the Northwest usually exports substantial power to California. At other times, California may export power to the Northwest.").

III. THE COMMISSION SHOULD IMPOSE A CAP IN THE PACIFIC NORTHWEST IDENTICAL TO THAT IN CALIFORNIA

14. As noted above, SDG&E, the Joint Movants, and others are seeking price caps for bids into the Cal ISO and Cal PX markets as low as (i) $100 per MWh

or (ii) the cost of service. Any price caps would, if granted, directly impact the Pacific Northwest. *See* Testimony at 9-10 ("One can expect . . . that a seller of electricity that has the option of selling its power in multiple markets likely will choose to sell in the market that offers the highest price. I do not therefore discount the possibility that prices in California may have influenced the prices asked to supply electricity to the Northwest or other Western markets.").[5]

15. Price caps of the kind requested for sales to the Cal PX and Cal ISO and those instituted by the Cal ISO for purchases are – *absent equivalent price caps on wholesale sales of energy and capacity into the Pacific Northwest* – fundamentally unfair to Pacific Northwest public utilities such as PSE and are antithetical to the development of a fair competitive wholesale power market in the Western Interconnection. Uneven application of price caps upsets the balance of purchase and sale market prices between California and the Pacific Northwest and violates Section 206 of the Federal Power Act because such uneven application is unjust, unreasonable, and unduly discriminatory or preferential. In short, it is unfair and unduly discriminatory to protect wholesale purchasers in California with a price cap and yet deny similar protection to wholesale purchasers in another part of essentially the same market, i.e., the

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[5] As noted above, the Commission has already concluded that the Cal ISO purchase price cap of $250/MWh is "disciplining" the prices in both the Cal ISO and Cal PX.

Pacific Northwest. The effect of such disparate treatment is to expose wholesale purchasers such as PSE in the Pacific Northwest to uncapped prices when they need power (e.g., to meet winter demand) and yet hobble their ability to offset the costs of such purchases with uncapped prices when they have surplus power (e.g., due to favorable hydro-electric generation conditions) for sale to California.[6]

16. Fundamental fairness and the desirability of avoiding unnecessary market distortions within the substantially integrated California and Pacific Northwest market dictate that the Commission institute a price cap for wholesale sales of energy and capacity into the Pacific Northwest that is equal to the lowest cap on prices established, ordered, or permitted by the Commission for wholesale purchases by the Cal ISO or CAL PX on wholesale sales of energy or capacity to California (whether to or through the Cal ISO or Cal PX or otherwise).

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[6] Given the substantial integration of the wholesale power market in California and the Pacific Northwest, it would be counterproductive for the Commission to impose or permit price caps on wholesale power sales or purchases into the Cal ISO or Cal PX without also establishing an equivalent price cap on wholesale power sales into the Pacific Northwest. This is because any price cap in California will tend to be ineffective insofar as it creates an incentive to export wholesale power out of California.

IV. OTHER MATTERS

17. *Refund Effective Date* (FPA Section 206(b)). The relief sought by PSE in this Complaint is prospective only, and PSE requests that any refunds ordered by the Commission reflect the prospective nature of the relief sought. If and to the extent any refund is called for in response to PSE's petition, PSE respectfully requests that the refund effective date be set, in accordance with Section 206 of the Federal Power Act (16 U.S.C. § 824e(b)), sixty (60) days after the date of filing of this Complaint.[7]

18. *Relevant Docket Numbers* (Rule 203(a)(1)). The Docket Numbers of proceedings relevant to this Complaint are EL01-1-000; EL00-95-000; EL00-98-000; EL00-104-000; and EL00-107-000.

19. *Name and address of each person against whom the complaint and petition is directed; Service of Complaint* (Rules 203(a)(5) and 206(c)). As noted above in footnote 1, PSE has served via first-class mail each party to the WSPP Agreement, as listed on

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[7] In addition, it would be unfair and arbitrary for the Commission to set a refund effective date for any Pacific Northwest utility in any proceeding before the Commission prior to the date requested by PSE herein because of the operation of the seasonal flow of power between California and the Pacific Northwest. A refund effective date prior to the date sought by PSE herein would harm Pacific Northwest consumers by exacerbating the differences in seasonal prices between the Cal ISO and Cal PX markets subject to a cap and the uncapped Pacific Northwest market.

the WSPP website, www.wspp.org. PSE has also electronically transmitted the Complaint to WSPP for posting on its website and requested that WSPP forward the Complaint electronically to each party to the WSPP Agreement. PSE requests that to the extent its actions as described above are not deemed to constitute substantial compliance with the requirements of Rules 203(a)(5) and 206(c), such requirements be waived.

20. *Dispute resolution* (Rule 206(b)(9)). PSE states that none of the dispute resolution mechanisms listed in Rule 206(b)(9) has been used and, given the nature as well as the urgency of the issues raised in this Complaint, PSE does not believe that alternate dispute resolution under the Commission's supervision is practicable.

21. *Notice of Complaint* (Rule 206(b)(10)). Attached to the Complaint and included herewith on a diskette is a Notice of Complaint suitable for publication in the Federal Register.

22. If and to the extent applicable, the remaining requirements set forth for Complaints in the Commission's Rules are contained in the body of the Complaint.

V. CONCLUSION

PSE respectfully requests that the Commission enter an order prospectively capping the prices at which sellers subject to the Commission's jurisdiction

may sell energy and/or capacity at wholesale into Pacific Northwest markets at a level that is equal to the lower of any purchase price cap instituted by the Cal ISO or the Cal PX and any sales price cap (whether as a cap on market prices or as a cost-of-service requirement) instituted by the Commission for sales into the California wholesale market, including the Cal ISO and the Cal PX. PSE also requests that, to the extent any refund is called for in response to this Complaint, the Commission set the refund effective date sixty (60) days after the filing of this Complaint.

Dated the 26th day of October, 2000.

Respectfully submitted,

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By /s/ Steve Marshall

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served in the manner stated in footnote 1 of this pleading.

Dated at Bellevue, Washington, this 26th day of October, 2000.

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95 FERC ¶ 61,418

UNITED STATES OF AMERICA
FEDERAL ENERGY
REGULATORY COMMISSION

Before Commissioners:
Curt Hebert, Jr., Chairman;
William L. Massey, Linda Breathitt,
Pat Wood III, and Nora Mead Brownell.

San Diego Gas & Electric Company,
Complainant,

v. Docket No. EL00-95-031

Sellers of Energy and Ancillary
Service Into Markets Operated
by the California Independent
System Operator Corporation
and the California Power Exchange,
Respondents.

Investigation of Practices of the California Independent System Operator and the California Power Exchange	Docket Nos. EL00-98-030 EL00-98-033
California Independent System Operator Corporation	Docket Nos. RT01-85-000 RT01-85-001
Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council	Docket Nos. EL01-68-000 EL01-68-001

ORDER ON REHEARING OF MONITORING AND MITIGATION PLAN FOR THE CALIFORNIA WHOLESALE ELECTRIC MARKETS, ESTABLISHING WEST-WIDE MITIGATION, AND ESTABLISHING SETTLEMENT CONFERENCE

(Issued June 19, 2001)

Introduction and Summary

On April 26, 2001, the Commission issued an order (April 26 Order)[1] establishing new price mitigation for sales in the California Independent System Operators (ISO) ancillary services and imbalance energy markets (spot markets).[2] The April 26 Order also instituted an investigation under section 206 of the Federal Power Act (FPA) into the reasonableness of the rates for wholesale sales in the spot markets[3] in the Western Systems Coordinating Council

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[1] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 95 FERC ¶ 61,115 (2001). On May 25, 2001, the Commission issued an order providing clarification and preliminary guidance on the implementation of the mitigation plan. 95 FERC ¶ 61,275 (2001).

[2] The price mitigation established in the April 26 Order replaced the price mitigation previously in effect for such sales, and is an outgrowth of a Commission investigation under section 206 of the Federal Power Act (FPA) of the reasonableness of rates for public utility sales through the markets operated by the ISO and the California Power Exchange (PX).

[3] As used throughout this document, the terms "spot markets" or "spot market sales" means sales that are 24 hours or less and that are entered into the day of or day prior to delivery.

(WSCC).[4] In so doing, we were mindful that the West is a single market which is at once inextricably interrelated, yet characterized by important differences. Fundamental in this regard is that the California spot markets are presently administered largely through the ISO's centralized clearinghouse, which operates a single price auction, while sales in the rest of the West are consummated on an individual bilateral contract basis and not through a centralized clearinghouse.

We have received and carefully considered many comments on how to change or improve our price mitigation in California and on whether and how to initiate price mitigation in the rest of the WSCC. Today, we will prescribe price mitigation for spot markets throughout the West which will guide the WSCC's energy markets through the difficult process of self-correction. In so doing, we seek to intervene in markets in as limited a manner as possible consistent with our responsibilities to ensure just and reasonable rates under the FPA, to rely on market principles wherever we can, and to balance carefully the need for price relief against the need for price signals to attract critical supply entry.

Today's order is one of a series of mitigation directives that began with our underlying order,

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[4] References throughout this document to the WSCC are intended to refer only to the United States portion of the WSCC.

issued December 15, 2000,[5] to correct dysfunctions in the wholesale power markets operated by the ISO and PX. Specifically, the elimination of the mandatory buy-sell requirement and the elimination of the PX rate schedule have helped to turn the tide in eliminating California investor-owned utilities' chronic reliance on spot markets. The effects of the price mitigation directed by our December 15 Order and the actions of the State of California in moving to longer-term contracts and conservation efforts have had a significant dampening effect on prices. As a result, California investor-owned utilities no longer rely on spot markets for meeting the entirety of the needs of the electric customers they serve. California now forecasts that it will only rely on the spot markets this summer for about 20% of its on-peak energy requirements, as compared to 100% prior to the December 15 Order.[6] In fact, in certain hours, the ISO data show no purchases whatsoever in its imbalance energy market. Because this market is the closest in time to when load must be met, it can exhibit the highest prices in times of shortage.

The reduction of the size of the ISO's spot market to levels more reflective of appropriate risk

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[5] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 (2000) (December 15 Order).

[6] Update of California Department of Water Resources Power Purchase Contract Efforts, California Department of Water Resources (May 31, 2001).

management was, and remains, the cornerstone of our price mitigation. The reduction of the size of California's spot market in conjunction with the mitigation plan adopted in our April 26 Order, as well as a dramatic reduction in gas prices and fewer generation outages in California, are among the factors that have had the effect of lowering energy prices in the West. Western power prices have fallen recently, with reports by the ISO citing peak daytime purchase costs of less than $100/MWh and off-peak power purchases of less than $20/MWh. During the week ending June 9, prices for last-minute peak power at Western trading hubs fell to less than $55/MWh from a high of about $170/MWh earlier in the week.[7] This trend continued into the week ending June 16 with prices hovering between $50/MWh and $65/MWh at most of the Western power indexes.[8] In addition, prices for Western forward contracts are also down dramatically, with year 2002 forward transactions dropping from $127 to $68/MWh, and 2003 forward contracts from $60 to $41 in the past month.[9]

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[7] Platts Power Markets Week, June 11, 2001. Prices of Spot Electricity, Week Ending June 9 – Daily On-Peak Indexes for Calif-Ore Border, Mid-Columbia, Palo Verde, Four Corners, North Path 15, and South Path 15 (Six Western Indexes).

[8] Megawatt Daily's Market Report, June 11 through June 14, 2001, for Six Western Indexes.

[9] Platt's Power Markets Week, June 11, 2001, pp. 1, 16. As used throughout this document, "forward contracts" or "forward transactions" means any transactions with a future delivery

(Continued on following page)

While progress has been made in correcting market dysfunctions, the dysfunctions will not be fully corrected until additional load is moved from the spot market to longer-term contracts (a mixed portfolio of supply contracts) and the basic structural defect of inadequate supply in the West is corrected. The Commission therefore has determined that in order to ensure that rates for sales for resale in spot markets in California and the rest of the WSCC continue to fall within a zone of reasonableness, we will provide for price mitigation in California and throughout the remainder of the WSCC during reserve deficiency hours, *i.e.*, when reserves in California fall below 7 percent (in California, Stage 1 is called when reserves fall below this level).[10] As we found in our April 26 Order, this is when the level of demand approaches the amount of available supply and suppliers have the greatest opportunity to exercise market power. In addition, based on the continents received and based on prices that we recently have observed in California in hours where there is no reserve deficiency, we conclude that as an added measure in protecting customers, at this time it is also appropriate to provide for a type of price mitigation for spot market sales during other hours.

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that are entered into more than 24 hours before commencement of service.

[10] Our April 26 Order referred to Stage 1 being called by the ISO when reserves in California fall below 7.5%. The correct number is 7%.

As noted, we find it appropriate to provide for price mitigation in the spot markets in California and throughout the West in reserve deficiency hours, *i.e.*, when reserves fall below 7 percent in California. As we found in our April 26 Order, at these times supply is scarce relative to demand and sellers have the greatest ability to dictate price. The price mitigation we will adopt for these hours will be based on market principles and will apply to California and the remainder of the West. Because there is no centralized clearinghouse for spot market sales in the WSCC other than in the ISO, and therefore no ability to develop a separate market clearing price for sales outside the ISO, we will apply the ISO market clearing price as the maximum price to all sales in the WSCC spot markets during reserve deficiency hours (Stage 1 or above) called by the ISO. We expect prices to be below this level to reflect the degree to which supply exceeds demand. Thus, our mitigation will apply to all sellers in the WSCC, including marketers and non-public utilities. It is critical to treat all sellers alike to remove the incentive to sell in one area versus another when a reserve deficiency is called by the ISO. We also will allow sellers other than marketers the opportunity to justify prices above the market clearing price during reserve deficiency hours and we will provide guidance on the specific showing that a seller must make.

In non-reserve deficiency hours, when supply is not scarce, prices should be disciplined sufficiently and should reflect an accurate measure of the

shortage confronting the West and provide a clear price signal to induce new supply. However, commenters are concerned that prices may remain high in hours when reserves are adequate. There is little doubt that regulators are ill-equipped to replicate the premiums which a functioning market assigns to a diminishing supply. It is precisely for this reason that, in our April 26 Order, we did not attempt to develop an administratively determined component for shortage and chose instead to rely on prices in non-reserve deficiency hours to send the correct price signal. Nevertheless, at this time, we will implement price mitigation in non-reserve deficiency hours as well. However, we will use a modified form of our present mitigation during non-reserve deficiency hours – to ensure that prices will continue to induce new supply. We do so as a discretionary matter to provide an added measure to protect customers and the economies of the Western states, even though we view prices above the marginal cost of generation in these hours as a necessary reflection of the supply shortage at hand. Instituting mitigation in these hours will protect customers so that all energies and attention can be harnessed on the tasks of adding new supply and upgrading energy infrastructure and of completing California's transformation from 100% reliance on the spot market to a balanced portfolio of short, medium and long-term supply arrangements, as well as protecting neighboring states from undue harm. Later in this order, we direct the State of California and parties in the *San Diego Gas & Electric Company* complaint proceeding to settlement

proceedings to complete the task of settling past accounts and structuring the new arrangements for California's energy future. We will monitor our price mitigation in non-reserve deficiency hours to ensure that it is providing the incentives needed to correct the present market dysfunctions. We will adjust the mitigation, as needed, to induce long-term supply entry and the forward contracts required to support that entry.

The price mitigation we are adopting again relies on market solutions and mechanisms to the maximum extent possible. We will continue to use a single market clearing price derived from must offer and marginal cost bidding requirements for hours of reserve deficiency in California's organized spot market. We also will adapt these market clearing prices for use in all other hours, both in California's spot markets and the West's spot markets. Before describing in general the price mitigation that will be required in the ISO's markets and in the bilateral spot markets in California as well as the rest of the West, we believe it is important to enumerate the major considerations we have balanced in developing appropriate price mitigation.

- There is a critical interdependence among the prices in the ISO's organized spot markets, the prices in the bilateral spot markets in California and the rest of the West, and the prices in forward markets.

- Uniform price mitigation for California and the balance of the West should reflect the same

essential competitive market principles, while recognizing the significant differences in the structure of those markets. It also should eliminate incentives for so-called "megawatt laundering".[11]

- In exercising our statutory responsibility to ensure just and reasonable rates, *i.e.*, rates that fall within a zone of reasonableness, we must balance the need for immediate price relief for customers against the need for price signals to attract new supply and demand-side investments.

- As mentioned in our prior orders, the cornerstone of remedying the dysfunctions in the energy markets in the West and in bringing both spot and forward prices down over the last few months is eliminating California's excessive reliance on spot markets. While significant progress has been made, some 20 percent of California's load remains in the ISO's spot markets at peak periods.[12]

- Buyers and sellers need certainty and closure. To the extent possible, our price mitigation should have clear rules, should set prices before they are charged and should not subject prices to change or adjustment after financial settlement of the day's transactions. Similarly, it should not rely on costly

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[11] The term "megawatt laundering" describes behavior where a supplier schedules supply out of state and then re-imports that power to avoid a mitigated price.

[12] Recent data indicates that the reliance on the spot market is higher during off-peak periods.

and time consuming administrative processes to set, adjust or justify prices.

- Abuse of market power cannot and will not be tolerated. Sellers will be subject to losing their market based rates for engaging in anticompetitive conduct. Further, as a condition of continued authorization of market-based rates, public utility sellers in the WSCC must agree to refunds, with interest pursuant to 18 C.F.R. § 35.19a, of any overcharges resulting from anticompetitive bidding or behavior.

To satisfy these principles, the mitigation plan will consist of the following measures:

- We will retain the use of a single market clearing price with must offer and marginal cost bidding requirements for sales in the ISO's spot markets in reserve deficiency hours, *i.e.*, Stage I when reserves are below 7 percent in California. Sellers in the ISO's single price auctions will receive the hourly market clearing price. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC) we will apply this clearing price as a maximum price. Sellers outside the ISO's single price auction will receive the prices they negotiate up to this maximum price. There are, however, three adjustments to the clearing price methodology we have previously used.

  First, marketers will be required to bid as price takers. This means that marketers cannot bid higher than the market clearing price.

> Second, we will require sellers that own generation to submit bids during reserve deficiencies that are no higher than the marginal cost to replace gas used for generation (*i.e.*, what the seller would pay to procure gas at the last minute) plus variable O&M costs.
>
> Third, we instruct bidders to invoice the ISO directly for the cost to comply with emissions requirements and for start-up fuel costs and direct the ISO to file a rate mechanism to bill those costs over the entire load on the ISO system. These cost inputs have proven too varied to standardize in a single market clearing price.

Sellers other than marketers will be allowed the opportunity to justify bids or prices above the maximum prices and we will provide guidance later in this order on what sellers that seek to do so must demonstrate.

• For spot market sales, both in the WSCC and in California, in all non-reserve deficiency hours (*i.e.*, when reserve levels in the ISO exceed 7%), we will adapt the use of these market clearing prices. Eighty-five percent (85%) of the highest ISO hourly market clearing price established during the hours when the last Stage 1 (not Stage 2 or 3) was in effect will, absent justification, serve as the maximum price for the subsequent period. For example, if the highest hourly market clearing price during a Stage 1 is $140/MWh, spot prices in all subsequent non-reserve deficiency hours beginning when Stage 1 is lifted can

be no higher than $119/MWh (*i.e.* 85 percent of $140/MWh). Sellers through the ISO's single price auction will receive the hourly market clearing price, but that clearing price will not exceed $119/MWh.[13] For example, if the market clears at $90/MWh all bidders in the ISO's auctions will receive $90/MWh for that hour. However, bids are limited to $119/MWh and, therefore, the clearing price during the period will never exceed $119/MWh. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC), sellers will receive the prices they negotiate up to the maximum price, in this example, up to $119/MWh. This maximum clearing price will remain in place until the next Stage 1 is declared and a new price is set. When that Stage 1 is lifted, 85% of the highest hourly market clearing price from that period will carry forward as the new maximum price. Sellers other than marketers will be allowed the opportunity to justify bids or prices above the maximum prices and we will later in this order provide guidance on what sellers that seek to do so must demonstrate.

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[13] As we explain later, the ISO is required to add 10 percent to the market clearing price paid to generators for all prospective sales in its markets to reflect credit uncertainty. This adder will not be reflected in the market price for the rest of the WSCC.

- The mitigation plan will become effective beginning on the day following the date this order is issued.[14]

- We will continue to apply all price mitigation to non-public utilities as a condition of selling into the spot markets which are the subject of this order and as a condition of using the interstate transmission grid under our jurisdiction.

- We will reaffirm that all public and non-public utilities who own or control generation in California must offer power in the ISO's spot markets. This requirement applies to any non-hydroelectric resource whether owned or under contract to the extent its output is not scheduled (or committed for minimum operating reserves) for delivery in the hour. We will also require all public and non-public utilities in the remainder of the WSCC to offer in the spot market of their choosing any non-hydroelectric resource whether owned or under contract to the extent its output is also not scheduled (or committed for minimum operating reserves) for delivery in the hour.

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[14] We will grant waiver of notice for the ISO's approved rate mechanism to recover the cost of emission requirements to be effective on the day following the date this order is issued. Absent a new reserve deficiency on the ISO's system declared before the effective date of the price mitigation outlined in this order, the market clearing price carried forward for non-reserve deficiency hours is $108.49/MWh (*i.e.* 85 percent of $127.64/MWh) (May 31, 2001, clock hour ending 1400).

- The price mitigation will terminate on September 30, 2002.

- We will establish settlement proceedings at this Commission to address any and all issues to ensure that California completes the transformation of its load to long-term contracts. The Parties in the *San Diego Gas & Electric Company* complaint proceeding and the State of California are directed to participate in good faith in these proceedings.

We emphasize that the rate mitigation prescribed in this order is part of a series of steps the Commission has taken to remedy dysfunctions in California wholesale power markets. However, as we recognized in our first remedial order on December 15, 2000, many of the critical remedies that need to be taken fall either wholly or in part within the jurisdiction of the State of California. In particular, the consummation of additional long-term wholesale contracts, the development of demand side response signals, the siting of new generation and transmission, and the construction of intrastate natural gas delivery infrastructure are critical to remedying the current market dysfunctions and are dependent on State action. We recognize the significant progress that California has made thus far and urge further implementation of these critical measures. We stand ready to assist in these efforts to the extent possible within our authority.

Finally, in taking action in today's order as well as in prior orders in these dockets, beginning on

December 15, 2000, the Commission has taken careful, reasoned steps to fulfill its statutory responsibilities under the FPA. The Commission's statutory responsibility to set just and reasonable rates gives it broad authority to adapt its ratemaking policies to the practical realities facing it. The Supreme Court ruled very early on that individual company cost-of-service rates were not the *sine qua non* of rate regulation, and that no single method of ratemaking is sacrosanct as the only means to reach the statutory goals. Rather, the value of any ratemaking policy is to be judged by its ability to meet the statutory goal of assuring that rates remain within a zone of reasonableness consistent with the maintenance of adequate service.

The ratemaking power granted the Commission under the FPA includes the authority to set the rules, regulations, practices, and contracts affecting rates, as well as the rates themselves. The Commission's orders related to the California markets have sought to establish a structure within which market forces will operate to achieve the statutory goal. In this order, the Commission continues the efforts of its earlier orders to modify the existing market structure throughout the West to minimize the potential for market power abuse, and thus to protect against possible unjust and unreasonable rates, while, at the same time, maximizing the incentive for increased supply in the entire western region.

I. Background

In an order issued August 23, 2000,[15] the Commission instituted formal hearing proceedings under section 206 of the FPA to investigate the justness and reasonableness of the rates for energy and ancillary services of public utility sellers into the ISO and PX spot markets, and also to investigate whether the tariffs, contracts, institutional structures, and bylaws of the ISO and PX were adversely affecting the wholesale power markets in California. These proceedings were intended to investigate the significant increases in the prices for energy and ancillary services in the California market.

In the December 15 Order, the Commission found that the market structures and rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy under certain conditions. The Commission, therefore, established a variety of remedies for the California wholesale electric markets, which included, in part, elimination of the mandatory PX Buy-Sell requirement, establishment of penalties for underscheduling load, a requirement for an independent governing board for the ISO, and a requirement

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[15] San Diego Gas & Electric Company, *et al.*, 92 FERC ¶ 61,172 at 61,606 (2000) (August 23 Order).

for the filing of generation interconnection procedures.

As an interim measure, the Commission also established a $150/MWh breakpoint under which public utility sellers bidding above the breakpoint receive their actual bids, but are subject to monitoring and reporting requirements to ensure that rates remain just and reasonable, including the potential for having to pay refunds for prices charged above the breakpoint.[16] The December 15 Order also required the development of a longer term mitigation plan to replace the interim breakpoint methodology by May 1, 2001.

On January 23, 2001, the Director of the Division of Energy Markets in the Office of Markets, Tariffs and Rates convened a technical conference to develop a plan to replace the interim breakpoint price.[17] Comments and reply comments on how to replace the interim break-point were filed with the Commission. In March 2001, Commission Staff issued a recommendation for prospective market monitoring and mitigation for the real-time electric market, and comments were filed on this proposal. The comments focused in particular on the method used for price

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[16] On March 9, 2001, the Commission issued an order directing public utility sellers to provide refunds (or offsets to amounts owed) or to provide cost or other justification for prices that exceeded the breakpoint. 94 FERC ¶ 61,245 (2001), *reh'g pending*.

[17] 93 FERC ¶ 61,294 at 61,983, 61,996-97.

mitigation and the periods when mitigation would be applied.

On April 26, 2001, the Commission issued its order adopting a prospective monitoring and mitigation plan for real-time California wholesale electric markets. The Commission's plan included the following elements:

> It enhanced the ISO's ability to coordinate and control planned outages during all hours.
>
> It required sellers with Participating Generator Agreements (PGAs), as well as non-public utility generators located in California that voluntarily make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), to offer all their available power in real time during all hours.
>
> It required public utility load serving entities to submit demand bids (identifying the price at which load will be curtailed) in the real-time market during all hours.
>
> It established conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anticompetitive bidding behavior in the real-time market during all hours.
>
> It required the ISO to submit weekly reports on schedule, outage, and bid data for all hours so that Commission staff can continue

to monitor generating unit outages and real-time prices.

It established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, beginning at a Stage 1 alert, which is defined as having reserves of 7 percent or less. Under this mechanism, the Commission established a formula (based on gas-fired generation) that the ISO can use to establish the real-time market clearing price when mitigation applies. Higher bids were permitted if they could be justified.

In the April 26 Order, the Commission also established an inquiry into whether a price mitigation plan similar to the one for California should be implemented in the WSCC. The order invited comment on how such a plan should be structured.

The parties listed on Appendix A have filed for rehearing of the April 26 Order. A number of parties have filed motions for late intervention. While the Commission ordinarily does not permit late interventions after an order has been issued solely to file for rehearing, the Commission will grant the late interventions in this instance because of extensive overlap of the issues between the California-oriented parts of the April 26 Order and the West-wide investigation instituted in that order, and the fact that the April 26 Order authorized additional comments and interventions for purposes of the latter. Appendix B lists those

filing comments in the section 206 proceeding with respect to the WSCC.

II. Discussion

As described earlier, the Commission is adopting a mitigation plan covering both California and the remainder of the WSCC during all hours for spot market sales. In the following sections, the Commission will address the rehearing requests and the West-Wide comments relating to this mitigation plan.

A. Outage Coordination

The April 26 Order found that in order to maintain sufficient generation capacity to meet market needs, the ISO must work with California generators to coordinate generating unit maintenance and outages, so that sufficient energy will be available when needed while also providing for reliable plant operation. The order required the ISO to make a tariff filing proposing a mechanism for outage coordination. The ISO made its compliance filing on May 11, 2001.

Most parties are in favor of such outage coordination. The CPUC, however, states that procedures relating to outage control and coordination are within the state's jurisdiction. CAC/EPUC contends that outage coordination may unreasonably burden QF facilities, because their outages are affected by their thermal host. DWR contends the outage controls should not be applied to hydroelectric generators.

Duke, on the other hand, protests the ISO's proposal and asks the Commission to clarify the need for truly cooperative standards and procedures.

The ISO has the authority to coordinate and control generation outage schedules for resources under PGAs. The Commission clarifies that only the ISO's outage coordination role will be extended to all other in-state generating facilities insofar as these generators must submit to the ISO maintenance schedules for their generating units. This will provide the ISO with the information necessary to maximize the efficient use of all in-state resources. For example, with this information, the ISO will be able to determine whether to schedule generation under its control based on when other generation resources will be out-of-service. The ISO, however, will not be authorized to schedule maintenance for units not under a PGA.

B. Selling Obligations

The mitigation plan requires those generators with PGAs, as well as non-public utility generators in California selling through the ISO markets or using the ISO's transmission lines, to offer the ISO all of their capacity in real time during all hours if it is available and not already scheduled to run. This must-offer obligation does not apply to power scheduled to run under bilateral agreements. The must-offer obligation does not apply to hydroelectric power because of its multi-purpose limitations (*e.g.*, irrigation,

recreation, and power production). The must-offer obligation is designed to prevent withholding and thereby to ensure that the ISO will be able to call upon available resources in the real-time market to the extent that energy is needed. The basis for this requirement is that, under competitive conditions, a generator that has available energy in real time should be willing to sell that energy at a price that covers its marginal costs, since it has no alternative purchaser at that time. The rehearing requests raise a number of issues that will be addressed below.

1. Applicability to Non-Public Utility Generators

A number of non-public utility entities request rehearing of the requirement that, because they make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), they must offer all their available power in real time during all hours. They primarily argue that the Commission is overstepping its jurisdictional bounds by asserting jurisdiction over them in violation of section 205 of the FPA.

CMUA, SMUD, and others contend that the Commission lacks jurisdiction over municipalities and other state agencies. CMUA maintains that "as far back as 1998, CMUA members have voluntarily made units available to the ISO, have sold the ISO energy on a regular basis in response to reliability calls, and continue to sell to creditworthy buyers."

CMUA at 8. CMUA contends that there is no evidence that such facilities are refusing unreasonably to sell in the ISO's markets.

The Commission denies the requests for rehearing. The Commission is not asserting jurisdiction over non-public utilities. Rather, as the Commission explained in the April 26 Order, it is exercising its conditioning authority to assure that all generators located in California, including non-public utility generators, that voluntarily sell into the ISO's spot market or that use the ISO's interstate transmission grid, offer their available power in California.[18] As we stated in the April 26 Order, if a non-public utility makes sales into the ISO's markets over which the Commission has exclusive jurisdiction or uses the ISO-controlled interstate transmission facilities, it must abide by the same conditions that are applicable to public utilities.[19] On rehearing, parties have raised no arguments that warrant a different result. We cannot meet our statutory responsibilities under the FPA to ensure just and reasonable rates in the Western spot markets if we allow non-public utilities to participate in the ISO's markets and use interstate

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[18] San Diego Gas and Electric Company, *et al.*, 95 FERC ¶ 61,115 at 61,356 (2001).

[19] *Id.* Since CMUA members already sell power on a regular basis to the ISO, and are assured of recovering their marginal costs when they run pursuant to the must-offer obligation, CMUA has not demonstrated that the Commission's actions would have an adverse effect on them.

transmission facilities, while refusing to comply with the measures necessary to ensure the justness and reasonableness of the ISO's rates and terms and conditions of service. In short, the Commission cannot ensure just and reasonable rates under the FPA unless non-public utilities, which sell power into the ISO's market or use the ISO's transmission lines, are subject to the same market rules as public utilities.

CAC/EPUC contends that imposing the must-offer obligation and the mitigation plan on QF facilities conflicts with the regulatory scheme established under the Public Utility Regulatory Policies Act of 1978 (PURPA). QFs that engage in sales for resale in interstate commerce and/or the transmission of electric energy in interstate commerce are public utilities and are therefore subject to the Commission's jurisdiction, although the Commission has exempted them from many provisions of the FPA.[20] However, because of the need for uniformity among all sellers, the Commission will not exempt QFs from the must-offer obligation and mitigation plan to the extent that QFs use the ISO's interstate transmission lines and make

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[20] Section 210(e) of PURPA states the Commission shall prescribe rules under which QFs are exempt, in whole or in part, from the FPA, PUHCA, and from state laws and regulations respecting rates or financial or organizational regulation. 16 U.S.C. § 824a-3 (1994). The Commission exempted most QFs from portions of the FPA, 18 C.F.R. § 292.601 (2000), PUHCA, 18 C.F.R. § 292.601(b) (2000), and from state laws and regulations respecting rates and financial and organizational regulation, 18 C.F.R. § 297.601(c) (2000).

sales through the ISO's markets.[21] The exemptions from regulation granted pursuant to PURPA to QFs do not mean QFs must or should be exempted from the must-offer obligation.

2. Extent of the Must-Offer Obligation

The predominant issue raised on rehearing is how to apply the must-offer obligation to thermal generators with environmental limitations on their operations. The April 26 Order stated that generators would not have to run if doing so would violate their certificate or applicable law. But it required those units to run if it involved only the paying of additional amounts to obtain emission credits to permit them to run outside their emission limitations.

A number of rehearings request clarification that generators do not have to run if doing so would violate certificates or subject them to possible criminal penalties or fines.[22] Sellers further maintain that units with maximum run limitations have legitimate opportunity costs that the Commission has failed to recognize.[23] They recognize that the issue of energy limited units is complex,[24] but that the Commission's

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[21] CAC/EPUC filed a request to stay the application of the mitigation plan as applied to QFs. Given the resolution of the rehearing request, the request for stay is denied.

[22] Rehearing Requests by MID, M-S-R, NCPA, TANC.

[23] Rehearing Requests by Dynegy, Mirant, Reliant.

[24] See Rehearing Request by Reliant.

proposed emission credit adder does not fully take into account the costs imposed by forcing these plants to run whenever the ISO determines. They argue that they have traditionally managed these units to ensure that they run only during the times of the year when they are most valuable and that they should not be required to run at other times without adequate compensation for the revenues they forgo.[25] Mirant maintains that exempting hydroelectric power from the must-run requirement while not exempting environmentally-limited gas units is discriminatory. Sellers maintain that the Commission should either eliminate the must-offer requirement or permit generators to include in their bids an amount to capture the economic value of losing the ability to generate in later years. Reliant maintains that application of the must-offer obligation to energy limited units should be conditioned on expansion of California Executive Order D-24-01 to sales into the ISO, so that run-time limits would not apply to such sales.

Municipals[26] similarly argue the Commission needs to make allowances for the possibility that imposing a must run obligation on a generator may impose additional price or cost risk at later periods of time. NCPA maintains that it is required to make use

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[25] For example, Dynegy maintains that forcing its units to run today will require it to use up emission credits allocated for the year 2003, and that it should be reimbursed for the lost opportunity of being unable to run that unit in the year 2003.

[26] Rehearing requests by NCPA, NRECA.

of its thermal plants to meet its member-customer needs and is concerned that if it is forced to run during particular periods, it may not be able to meet the power needs of its members in later periods, if it is unable to obtain additional emission credits. It therefore requests clarification that it not be required to honor the must offer obligation unless it is able to obtain additional air pollution credits and that it be permitted to include those credits in any bid it makes into the ISO. Municipal generators request clarification that they do not have to make power available to the ISO when that power is being used to serve their own retail load or is required as reserves under interconnection agreements.[27] They contend that the April 26 Order was not clear whether the requirement to serve retail loads would be considered the equivalent of bilateral contracts. CAC/EPUC contends the must-offer obligation should not be applied to QF facilities, because it interferes with the QF's obligation to its thermal host, which is governed by a contract or operational protocol. Calpine similarly argues that QF units with capacity committed to a utility are not subject to the must-offer even if it chooses not to operate at maximum capacity.

The Commission clarifies that generators should not be exempt from the must-offer requirement absent a showing that running the unit violates a

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[27] MID, M-S-R, TANC.

certificate, would result in criminal violations or penalties, or would result in QF units violating their contracts or losing their QF status. Many of these issues are within the domain of the State of California, and we strongly urge California to modify current policies to enable generators to run during this period of scarce supply. For municipal generators the must-offer obligation applies only to available power remaining after the municipality satisfies its own retail load and contractual obligations. Given the shortage of power in California, all generators in California, including municipals, should not hold energy in reserve (over minimum acceptable levels) when the energy is needed to meet demand.

For QF facilities, like other generators, the must-offer obligation applies to energy that is available from generation that is not already contractually committed or would not violate its contractual obligation to its thermal host. With respect to Calpine's argument, a QF with capacity committed to a utility is, therefore, subject to the must-offer obligation if it chooses not to sell its maximum output to the utility. With respect to CAC/ EPUC's contention, the Commission has granted waivers of the operating and efficiency standards so that QFs, without jeopardizing their QF status, can generate power regardless of whether the host needs thermal energy.[28] Therefore,

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[28] *See* San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,238 at 61,772 & n.3 (2000) (December 8 Order) (granting temporary waiver of QF

(Continued on following page)

QF facilities will be expected to produce available energy regardless of whether the host requires thermal energy.

Due to the severity of the power shortage in the WSCC in general, and in California specifically, the Commission finds that the incurrence of expenses for obtaining additional emission allowances is not a valid reason to withhold available energy from the ISO's market. As discussed later in this order, the Commission is providing a mechanism for generators that incur emission related expenses to recover those costs through the ISO. Moreover, the Governor of California signed an Executive Order, D-40-01, allowing generators to exceed their emission runtimes without losing valuable future emission allowances, provided the energy is sold to DWR (or another California buyer) or dispatched by the ISO. Therefore,

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regulations); San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 93 FERC ¶ 61,294 at 62,018 (December 15 Order) (extending waivers); Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 at 61,970-71 (March 14 Order) (extending QF waivers); Further Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 95 FERC ¶ 61,225 at 61,767-68 (2001) (May 16 Order) (waivers extended to entire WSCC and through April 30, 2002). In a second order issued on May 16, the Commission required California Utilities to provide interconnection and transmission service to QFs pursuant to existing agreements to permit certain sales of QF power to third-party purchasers. San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, 95 FERC ¶ 61,226 (2001).

exceeding today's emission limits will not affect future limits. Thus, Executive Order D-40-01 moots all arguments on this issue insofar as California generators are concerned, including those of the municipal generators.

3. Withholding Generation for Operational Reasons

Mirant, Reliant, and Williams maintain that the must-offer obligation fails to recognize the need to withhold generation to cover the possibility that a unit will unexpectedly go offline. They take issue with the statement in the April 26 Order that a generator cannot be financially harmed from offering all of its units because the generator will only have to pay for the cost of replacement power, which is the same amount the generator would earn if the unit ran. They argue that, while this statement is true in theory, it does not apply to the ISO's markets because due to penalties in the ISO's tariff and the manner in which the ISO computes the cost of replacement energy, the generator would have to pay more for replacement energy than it would receive for the unit's bid in the market.

The must-offer obligation is crucial to ensuring that all capacity is in the market when needed and tariff provisions should not inhibit the fulfillment of this obligation. The Commission finds that during the periods mitigation is in effect, the current ISO tariff provisions in this regard are unjust and

unreasonable, and, therefore, we will require the ISO to modify its tariff, to be effective the day after the date of this order, so that the only penalty for having a unit forced out of service is the cost of replacement energy. The must-offer obligation modifies various market rules that existed when the current penalty provision was accepted for filing.

4. Other Issues

Several rehearing requests are concerned about generators avoiding the must-offer requirement through so-called "megawatt laundering" where a generator sells power to an out-of-state marketer, who then reimports that power to avoid a mitigated price.[29] The Commission clarifies that the must offer obligation applies to all sellers who own or control generation by contract. Moreover, the mere fact that a generator has a contract to provide power to a marketer does not exempt the generator from the must-offer obligation for energy that the marketer is not scheduling. As long as the generator has available energy, the generator has the obligation to offer that power into the ISO's auction market. Moreover, as described later, all marketers in the ISO's markets must now be price takers and cannot justify a bid higher than the mitigated price.

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[29] Rehearing Requests by ISO, CMUA, Metropolitan, NCPA, SMUD, San Diego, Edison.

Dynegy maintains the must-offer obligation should be limited to emergency hours only. It argues that had this obligation been imposed at the time it purchased the plants, it would have paid a lower amount. It therefore contends the must-offer obligation unfairly changes the contractual conditions under which it purchased the plants. The Commission rejects Dynegy's argument. The must-offer obligation must be applied in all hours in order to ensure that all available capacity is in the market and that none is being withheld, except for the reasons previously discussed. Moreover, mitigation is now being applied in all hours, so the must-offer obligation must also be applied to all hours.

LADWP requests clarification that the must-offer and price mitigation aspects of the order do not apply to its sales of energy under bilateral contracts or to sales or purchases that are scheduled to run in real-time pursuant to a bilateral contract. All public and non-public utilities which control generation in California must offer power in the ISO's spot markets. This requirement applies to any non-hydroelectric resource whether owned or under contract only to the extent its output is not scheduled for delivery (or committed for minimum operating reserves) in the hour. All public and non-public utilities in the remainder of the WSCC must offer in a spot market of their choosing any non-hydroelectric resource whether owned or under contract to the extent its output is not scheduled for delivery (or committed for minimum operating reserves). All sales in these spot

markets are subject to the price mitigation established in this order.

The rehearing requests raise issues with respect to the effect of the must-offer obligation on the ISO's authority to curtail exports of power to other markets. Reliant and Mirant maintain the must-offer requirement should supplant the ISO's curtailment authority under its tariff. Reliant contends the curtailment authority is unnecessary now that California generators will be bidding all available supply into the real-time market. Williams maintains the ISO should compensate generators for curtailments. SDG&E, on the other hand, contends the Commission should permit the ISO to curtail in-state generation destined for other states.

The Commission is not persuaded to change the ISO's curtailment authority at this time. Since Reliant maintains that this authority is no longer needed as a result of the must-offer obligation, it has not demonstrated how it is harmed by leaving the current authority intact. The price mitigation adopted in this order establishes the same price throughout the WSCC as in California, and therefore does not provide a financial incentive for generators to sell energy outside of California. Parties may renew objections to this authority in future proceedings if they can establish discernible harm.

C. Demand Response

The April 26 Order provided that beginning on June 1, 2001, each public utility purchasing electricity in the ISO's real-time market is required to submit demand-side bids that will indicate the price at which load will be curtailed and will identify the load to be curtailed.

The ISO requests clarification as to whether the demand response mechanism is voluntary or mandatory. If voluntary, the ISO maintains that it is already implementing a number of demand response mechanisms, If the requirement is mandatory, a number of rehearing requests contend that it is insufficient to solve the problem,[30] and is technically infeasible, in the short-run, because there is no mechanism for obtaining accurate demand response signals from all customers. In addition, the ISO cannot currently curtail power to individual loads.[31] Parties assert that load serving entities should not be required to simply guess at the prices its customers are willing to pay. SDG&E, for example, contends that the CPUC did not permit it to act as an aggregator for demand responses, and accordingly it would simply be guessing at what price its customers are willing to pay. San Francisco maintains that curtailing retail customers is anathema to the Load Serving Entities' (LSEs') duty to serve. A number of

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[30] See Rehearing Request by CMUA,

[31] Rehearing Requests by ISO, DWR, San Francisco.

requests contend that demand response is a state concern, and the Commission has no authority to indirectly regulate retail customers. Others contend that since the DWR is not a public utility, it would not be covered by the demand response mechanism in any event.

On the other hand, generators maintain that a demand response mechanism is crucial to establishing a viable market and is needed to provide generators with appropriate scarcity rents.

The Commission continues to believe that establishing a demand response mechanism is crucial to establishing a robust market.[32] Without a demand response mechanism, the ISO is forced to work under the assumption that all customers have an inelastic demand for energy and will pay any price for power. There is ample evidence that this is not true. Many customers, given the right tools, can and will manage their demand. Such an assumption inevitably leads to higher prices during times of shortage, since high supply bids do not lead to a reduction in power purchased. A working demand response program puts downward pressure on price, because suppliers have additional incentives to keep bids close to their marginal production costs and high supply bids are

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[32] *See* Chandley, Harvey, & Hogan, Electricity Market Reform in California, at 25 ("The least controversial reform of market design would be to implement all the changes needed to allow for demand side response in the face of higher prices." (Attached to November 22, 2000 Comments of SDG&E).

more likely to reduce the bidder's energy sales.[33] Appropriate price signals to customers thus helps to mitigate market power as high supply bids are more likely to reduce the bidders' energy sales, Suppliers thus have additional incentive to keep bids close to their marginal production costs. Demand-side price-responsive bids will also help to allocate scarce supplies efficiently.

Indeed, without demand-side price responsiveness, there can be no market mechanism for ensuring that scarce supplies are allocated to the highest valued uses during shortages. However, based on the technical impracticalities raised in the rehearing comments, the Commission does not find that the demand response requirement should be implemented at this time. Because the development of demand response is so critical, we expect that buyers in the ISO's market will submit demand bids as soon as demand bidding becomes technologically feasible. Meanwhile, the Commission will continue to monitor developments in California to determine whether additional Commission action is needed. The ISO must include in its quarterly reports a discussion of all demand response changes that have been

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[33] Already conservation has helped to reduce demand. *See* Peter Behr, "Fears of an Energy Crisis Begin to Dim, Consumption Cuts Help Lower Prices for Gasoline, Natural Gas and Electricity," Washington Post, April 8, 2001, at E1 (California has reduced demand 8%). A properly designed demand side response program could improve this performance even more markedly by providing price incentives for reduction.

implemented. If state programs for demand response do not develop, the Commission expects the ISO to enhance its own programs.[34]

Public utilities along with California officials also must actively pursue such approaches to achieving a viable demand response program. As SDG&E points out, LSEs can effectively act as aggregators for retail demand response. SDG&E and other public utilities should continue to pursue demand response initiatives and are required to file with the Commission by September 14, 2001 a report of the progress that is being made in establishing these mechanisms and any difficulties they have encountered.

To help facilitate these initiatives, the Commission intends to conduct a staff technical conference to explore how demand response can be increased. The first purpose of the conference will be for the Commission to familiarize itself with the status and availability of conservation, demand-side management, and other innovations to help communicate real-time price signals to consumers, including the software and metering necessary to support such programs. The second purpose will be to explore how these programs can be implemented. At the conclusion of

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[34] Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272 at 61,972-73 (March 14 Order) (DSM programs); Further Order Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 95 FERC ¶ 61,225 (2001) (May 16 Order).

the conference, the Commission will reconsider the feasibility and schedule for a demand bidding requirement and its use in establishing prices in the ISO's market.

D. Price Mitigation for California and the WSCC

The April 26 Order applied price mitigation to periods of reserve deficiency, defined as those periods beginning with Stage 1. Under the approach set forth in the April 26 Order, the ISO would conduct a market clearing auction for its real-time markets. During periods of reserve deficiency, however, the ISO would calculate a marginal cost bid for each generator by using a proxy for the gas costs, emission cost, and operation and maintenance (O&M) expenses. The ISO would then use the bid of the last unit dispatched to establish the market clearing price. The justification for this approach is that as reserves are reduced, all sellers are aware of how tight supplies are relative to the amount they have to offer. Thus, sellers have an incentive to offer supply at prices above that which they would ordinarily bid. Because of the imbalance of supply and demand, these prices may not be just and reasonable. The Commission, however, did not impose mitigation during periods of reserve sufficiency because there is less risk that prices would exceed those charged in a competitive market. During reserve sufficiency conditions a supplier has less of an incentive to bid a high

price, because it cannot be sure it will be dispatched, since other generators may offer lower bids.

Many rehearing requests, as well as comments in the West-Wide proceeding, contend the Commission should have extended mitigation to cover all hours. They contend that evidence from a number of studies shows that sellers have been able to exercise market power during all hours. They contend that the Commission has the obligation under the FPA to assure just and reasonable rates in all hours.[35] Duke Energy and other generators insist that the record does not show that market power has been exercised.

As described earlier, the Commission here is instituting a two-part approach to price mitigation for spot markets to cover all hours for California and the WSCC. Because these markets are integrated, the mitigation proposal must establish the same prices for all markets in order to prevent arbitrage where power is diverted from the lower priced market to the higher priced. The mitigation plan further has to recognize the differences between the California market, which has an organized auction, and the remainder of the WSCC, which does not have a similar centrally organized market. The plan adopted by the Commission is tailored to provide a uniform scheme of mitigation that at the same time recognizes the

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[35] Rehearing Requests by ISO, CEOB, CMUA, Assembly, City of Anaheim, *et al.*, CFA, Metropolitan, PG&E, NCPA, SDG&E, San Diego, San Francisco, Seattle, Edison, SCWC.

differences between these markets. During non-reserve deficiency hours in California, the Commission will adapt the ISO's market clearing price for spot market use West-wide.

The purpose of instituting this dual plan is to stabilize the market in the short-term and permit California time to repair its market mechanisms. The shortage of hydroelectric power together with the failure to build efficient generation is clearly a major part *of* the problem. This has been exacerbated by the imbalance between high wholesale prices and low retail prices, which do nothing to dampen demand. What *is* clear, however, is that a major contributor to the high prices was the deficient market mechanisms initially established by California, and approved by the Commission, that have resulted in a dysfunctional marketplace both in California and the remainder of the West. The mitigation plan established in this order, in effect, provides breathing room for the markets to right themselves.

The ISO, CPUC, and PG&E further contend that mitigation should apply outside of the ISO's Imbalance Energy market and should include its Day-Ahead and Hour-Ahead markets for ancillary services and its congestion management market. The Commission's order providing clarification and preliminary guidance addressed these issues.[36]

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[36] San Diego Gas & Electric Company, *et al.*, 95 FERC ¶ 61,275 (2001).

Several rehearing requests contend the mitigation should apply to all bilateral contracts.[37] The section 206 proceeding involving the ISO was limited to the ISO's and PX's real-time markets and did not extend to bilateral markets.[38] As discussed, however, in the Commission's section 206 investigation of the non-ISO spot markets in the WSCC, we have determined it appropriate to also apply mitigation to the bilateral spot markets in the WSCC, including California. Parties have not provided justification for extending the scope of our investigation or the mitigation to bilateral transactions other than spot markets. Moreover, any mitigation applied to the ISO's real-time markets will, over time, impact bilateral and forward markets as well.

A number of parties argue that the Commission's market monitoring and mitigation plan will not result in just and reasonable rates as required by the Federal Power Act, and the Commission should either return to individual cost-of-service rates or condition the continued use of market-based rates on effective mitigation measures.[39] The CPUC maintains that because the Commission found rates to be unjust and

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[37] Rehearing Requests by CPUC, City of Anaheim, *et al.*, PG&E.

[38] San Diego Gas & Electric Company, *et al.*, 93 FERC ¶ 61,121, at 61,349 (2000) (limited proceeding to real-time markets).

[39] *See, e.g.*, ISO, CEOB, CPUC, Assembly, CFA, PG&E, San Francisco, Seattle, and Edison.

unreasonable, the Commission is required to fix by order just and reasonable rates. It declares that "[w]here, as here, market power is pervasive through the industry in the west, FERC must impose cost of service pricing."[40] PG&E asserts that the Commission should immediately suspend the existing market-based rates of all sellers in the West and that the Commission should require immediate cost of service filings.[41] CEOB maintains that "[t]he Commission has no choice but to engage in cost-based ratemaking, or to adopt a sweeping mitigation scheme throughout the WSCC to ensure just and reasonable rates. . . ."[42]

Since determining that the market structure and rules for wholesale sales of electric energy in California had caused, and continued to have the potential to cause, unjust and unreasonable rates for short-term energy during certain times and under certain conditions, the Commission has ordered changes to the market structure and rules to assure that future rates would be just and reasonable.[43]

After carefully considering the record, the Commission reaffirmed its general finding that, as a result of the seriously flawed electric market structure

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[40] CPUC Request for Rehearing at 7.

[41] PG&E Request for Rehearing at 13-15.

[42] CEOB Request for Rehearing at 4.

[43] FERC's remedial measures "must be construed as a whole in, assessing FERC's compliance with FPA § 206". In re California Power Exchange Corp., 245 F.3d 1110, 1120 (9th Cir. 2001).

and rules for wholesale sales of electric energy in California, unjust and unreasonable rates were charged, and could continue to be charged during certain times and under certain conditions, unless certain targeted remedies were implemented. *San Diego Gas & Electric Co., et al.* 93 FERC ¶ 61,294 (2000) ("December 15 Order").[44]

The following remedies were adopted by the Commission in order to correct the specific flaws identified through the investigatory and hearing process: (1) because "the mandatory participation requirement . . . [was] producing rates that [were] not just and reasonable during certain periods," the Commission eliminated the requirement that the IOUs sell all of their generation into and buy all their energy needs from, the PX; (2) recognizing that it could assure the justness and reasonableness of California wholesale markets prices only by eliminating the PX's exclusive mandatory exchange, the Commission terminated the PX's wholesale tariffs; (3) to

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[44] The Commission has freedom, "within the ambit of [its] statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances. "FPC v. Natural Gas Pipeline Co., 315 U.S. 575, 586 (1942); In re California Power Exchange Corp., 245 F.3d at 1120. FPA § 309, 16 U.S.C. § 825h, gives the Commission the necessary flexibility to take unusual remedial action in appropriate circumstances. *See* Permian Basin Area Rate Cases, 390 U.S. 747, 776 (1968) (applying NGA § 16, the counterpart of FPA § 309, the Court held that "the Commission's broad responsibilities . . . demand a generous construction of its statutory authority."); FPC v. Louisiana Power & Light Co., 406 U.S. 621, 642 (1972) (same).

eliminate market participants' chronic underscheduling with the ISO, which jeopardized ISO system operations and created a strong sellers' market and higher prices in the most volatile spot market (real-time imbalance), the Commission required market participants to preschedule 95 percent of their load, with penalties for scheduling deviations in excess of five percent of an entity's hourly load requirements and disbursements of penalty revenues to all loads scheduled accurately; (4) mindful that eliminating the mandatory buy/sell requirement would move a considerable amount of load into the forward long-term markets all at once, the Commission established, effective for one year, an advisory benchmark for pricing five-year contracts; (5) because of concerns about the independence and effectiveness of the ISO governing board, the Commission ordered that the current stakeholder governing board be replaced by a non-stakeholder board composed of members independent of market participants; and (6) the Commission required the ISO and the IOUs to file generation interconnection procedures to facilitate the interconnection of new generators or existing, upgraded generators, thereby enhancing system reliability and reducing price volatility.

To further assure that prices in the ISO's and PX's spot markets are just and reasonable, the Commission directed that a technical conference be held to develop a comprehensive and systematic monitoring and mitigation program to be submitted to the Commission by March 1, 2001. Until that date,

the Commission established an interim $150/MWh breakpoint for spot market sales. On an interim basis, g public utility sellers bidding at or below $150/MWh would receive the market clearing price up to $150/MWh, and only those sellers bidding above $150/MWh would receive their actual bid price. However, all accepted bids above $150/MWh were required to be reported to permit proper monitoring and review by the Commission.

On April 26, 2001, the Commission adopted a prospective monitoring and mitigation plan for real-time California wholesale electric markets which replaced that previously in effect. The Commission's plan: (1) enhanced the ISO's ability to coordinate and control planned outages; (2) required sellers with PGAs, as well as non-public utility generators located in California that voluntarily make sales through the ISO's markets or use the ISO's interstate transmission grid (with the exception of hydroelectric power), to offer all their available power in real time during all hours; (3) required public utility load serving entities to submit demand bids (identifying the price at which load will be curtailed) in the real-time market during all hours; (4) established conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anti-competitive bidding behavior in the real-time market during all hours; (5) required the ISO to submit weekly reports on schedule, outage, and bid data for all hours so that Commission staff can continue to monitor generating unit outages and real-time prices;

(6) established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, beginning at a Stage 1 alert (*i.e.*, when reserves are below 7 percent). This mechanism provided a formula (based on gas-fired generation) for the ISO to use to establish the real-time market clearing price when mitigation applies. Higher bids were permitted if they could be justified.

In this order, the Commission is expanding the market monitoring and mitigation plan to produce spot market prices in all hours that are just and reasonable and emulate those that would be produced in a competitive market. We find that a return to individual cost-of-service ratemaking is unwarranted. As addressed above, the market changes and monitoring procedures already implemented by the Commission have improved the wholesale power markets in California. This order continues that effective course. In contrast, cost-of-service ratemaking tends to penalize more efficient generators and not provide proper incentives for generators to become more efficient, since each generator's price is dependent on its costs.[45] Moreover, individual cost-of-service rates may not provide generators with appropriate scarcity rents. Establishing individual cost-of-service rates is also difficult with respect to spot markets. For

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[45] *See* National Rural Telecom Association v. FCC, 988 F.2d 174, 178 (D.C. Cir. 1993).

peaking units, decisions would need to be made about the number of projected MWhs over which to spread costs. Generators also would have to make filings establishing their rate base, acceptable rate of return, and cost-of-service, possibly including trackers for volatile costs such as gas and emissions fees. Resolving the issues involved in such filings would be protracted and would not provide price certainty to the market. We do provide for any generator unable to work within the revised mitigation framework the opportunity to apply for cost-based rates for the duration of the plan.

The monitoring and mitigation plan adopted by the Commission in this order satisfies the requirements of the FPA. In particular, FPA Section 206 allows the Commission to determine whether "any rate, charges, or classification . . . or any rule, regulation, practice, or contract affecting such rate, regulation or classification" is unjust or unreasonable, and to fix "the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force." 16 U.S.C. § 824e(a) (1994). In this order, as in our earlier orders related to this matter, the Commission has examined the rules, regulations, practices and contracts that are currently being used, and made changes that are necessary to prevent possible abuses that could lead to unjust and unreasonable rates.

The focus on changes to the existing market structure, rather than on setting cost-of-service rates for individual sellers, is consistent with the case law.

As the Supreme Court made clear, it "has never held that the individual company cost-of-service method is a *sine qua non* of natural gas [or electric] rate regulation."[46] Nor has the Court limited ratemaking agencies "to the service of any single regulatory formula; they are permitted, unless their statutory authority otherwise plainly indicates, 'to make the pragmatic adjustments which may be called for by particular circumstances.'"[47] The success of a particular ratemaking approach is judged by "the result reached not the method employed."[48] The end result of any ratemaking order must be to provide rates within a zone of reasonableness that "take fully into account the probable consequences of a given price level for future programs of exploration and development".[49] As that language makes clear, a cost-based inquiry alone would not be sufficient in these circumstances to fulfill the statutory duty. Rather, the Commission must consider the broader public interest, and, in particular, the interest in setting rates that will assure adequate supply.[50]

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[46] Wisconsin v. FPC, 373 U.S. 294, 309 (1963).

[47] Permian Basin Area Rate Cases, 390 U.S. 747, 776-77 (1968).

[48] FPC v. Hope Natural Gas Company, 320 U.S. 591, 602 (1944).

[49] Permian Basin, 390 U.S. at 797; *see* Atlantic Refining Co. v. Pub. Service Comm., 360 U.S. 378, 388 (1959) (same).

[50] Permian Basin, 390 U.S. at 796-97; Mobil Oil Corp. v. FPC, 417 U.S. 283, 317-18 (1974); Consumers Union v. FPC 510 F.2d 656, 660 (D.C.Cir. 1974); *see also* Central Iowa Power Coop

(Continued on following page)

The Commission is free to adopt market-based rates.[51] In adopting market-based rates, the Commission must: (1) provide a clear and reasoned analysis of the need for market-based pricing to promote the statutory objectives of the FPA; (2) support its decision with substantial evidence; and (3) assure that the resultant market-based rate falls within a "zone of reasonableness."[52] Having adopted a market-based approach for the California market, nothing

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v. FERC, 606 F.2d 1156, 1165 n. 28 (D.C.Cir. 1979) (affirming rate based on "need to stimulate short-term purchases of excess capacity in lieu of adding new capacity and to discourage reliance on emergency energy when units are less than efficient").

[51] *E.g.*, Louisiana Energy and Power Authority v. FERC, 141 F.3d 364 (D.C. Cir. 1998); Elizabethtown Gas Company v. FERC, 10 F.3d 866, 870 (D.C. Cir. 1993); *see also* Midcoast Interstate Transmission, Inc. v. FERC, 198 F.3d 960, 968 (D.C.Cir. 2000). Other agencies subject to ratemaking regimes similar to that of the FPA have been upheld in adopting a market-based, rather than a cost-of-service, approach to setting rates. See Nat'l Ass'n of Regulatory Util. Comm'rs v. FCC, 737 F.2d 1095, 1137 (D.C. Cir. 1984); Nat'l Rural Tel. Ass'n v. FCC, 988 F.2d 174 (D.C. Cir. 1993); Consolidated Rail Corp. v. U.S., 812 F.2d 1444 (3d Cir. 1987); Potomac Elec. Power Co. v. ICC, 744 F.2d 185 (D.C.Cir. 1984).

[52] In Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486 (D.C. Cir. 1984), *cert. denied sub nom.* Williams Pipe Line Company v. Farmers Union Central Exchange, Inc., 469 U.S. 1034 (1984), the court explained that it may not invalidate "rate orders that fall within a 'zone of reasonableness,' where rates are neither 'less than compensatory' nor 'excessive.'" It added that "when FERC chooses to refer to non-cost factors in ratesetting, it must specify the nature of the relevant non-cost factor and offer a reasoned explanation of how the factor justifies the resulting rates."

requires the Commission to revert to a cost-of-service ratemaking approach whenever it finds flaws in the market structure. *See, Environmental Action v. FERC,* 996 F.2d 401, 411(D.C. Cir. 1993) (finding that the Commission "has never bound itself to a rule requiring either rigid regulation or textbook markets"). The courts have also approved the use of marginal cost pricing as an appropriate regulatory tool. *Town of Norwood v. FERC,* 962 F.2d 20, 22 (D.C. Cir. 1992) (stating "one of the best-established precepts of classical economics: social welfare is maximized when the marginal cost of purchasing any commodity is equivalent to the marginal cost of producing it.") See *Electricity Consumers Resources Council v. FERC,* 747 F.2d 1511 (D.C. Cir. 1984) (same).

Rather, in such circumstances, the presence of a monitoring program under which the Commission can take appropriate action to restructure the market is key. For example, in *Elizabethtown,* the court found that the continued "exercise of the Commission's NGA] § 5 authority . . . to assure that a market (*i.e.*, negotiated) rate is just and reasonable" sufficiently safeguards against abuses under a market pricing approach. 10 F.3d at 870. Similarly, in *Environmental Action,* the court approved the combination of price ceilings and complaint procedures as sufficient safeguards because that would allow "competitive forces, not market power, [to] determine most transaction prices . . . and serve to extend competitive pricing to

situations where market power might otherwise prevail." 996 F.2d at 413.[53]

Through the remedies ordered in earlier orders and herein, the Commission determined and is continuing to determine pursuant to FPA Section 206 "the just and reasonable rate, charge, classification, rule, regulation, practice, or contract" to replace flawed structure and rules, and to "fix the same by order." The Commission was not obliged to set seller-specific cost-based rates to resolve the perceived problems, given its continuing monitoring and review of the situation which offers adequate safeguards against potential market abuse. The mitigation plan adopted in this order relies on market solutions and mechanisms to the maximum extent possible, consistent with the Commission's statutory responsibilities to maintain just and reasonable rates. The revisions made in this order are designed to provide a structure that will minimize potential market power abuses, thus lowering customer rates, while also encouraging adequate supply in the market for the immediate future.

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[53] The courts have approved market pricing for other agencies if available remedies assure that market power will not be abused. E.g., Ford Motor Co. v. ICC, 714 F.2d 1157, 1158-59 (D.C. Cir. 1983); Arkansas Power & Light v. ICC, 725 F.3d 716, 718 (D.C. Cir. 1984); Coal Exporters Ass'n v. U.S., 745 F.2d 76, 80 and 90 n. 18 (D.C. Cir. 1984); Arizona Public Service Co. v. U.S., 742 F. 2d 644, 647 (D.C. Cir 1984).

E. ISO Market Clearing Auction During Periods of Reserve Deficiency

Under the April 26, 2001 mitigation plan, each gas-fired generator in California (both those signing PGAs and covered non-public utility gas-fired generators) will file with the Commission and the ISO (on a confidential basis) the heat rate and emission rate for each generating unit. The ISO would use these heat rates to calculate a marginal cost for each generator by using a proxy for the gas costs, emission cost, and a $2.00/MWh adder for O&M expenses. The gas cost proxy was based on an average of the daily prices published in Gas Daily for all California delivery points. The emission cost was to be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for the unit. All generators would be paid a single market clearing price reflecting the last unit dispatched calculated using the proxy prices.

Rehearing requests addressed a number of elements of this plan. Based on those rehearing requests, the Commission, as discussed in detail below, is modifying the method of determining the cost for gas, the treatment of emission costs, and the O&M adder. The Commission will address below the rehearing requests with respect to the ISO auction mitigation plan.

1. Use of the Marginal Cost of the Last Unit Dispatched

PG&E maintains the Commission should not determine price using the marginal cost of the last unit dispatched. Instead, it maintains the Commission should use the heat rate of the average cost unit. PG&E maintains that in a competitive market, each unit of generation would recover only its own marginal costs.

In a competitive market, however, each generator would not receive only its own marginal cost, as PG&E asserts. Competitive markets clear at a single price, which is effectively set by the marginal cost of the last unit produced. All more efficient units will receive the same price, which creates an incentive for firms to increase their efficiency. Therefore, using the marginal cost of the least efficient generating unit dispatched best replicates prices in a competitive market. In 1998 and 1999, when the California spot markets were producing average annual wholesale prices of $29 and $31 per MWh, respectively, the marginal cost of the last unit dispatched set these prices. The mitigation plan simply returns the market to the competitive principles that existed in 1998-99.

The ISO contends that inflexible units such as combustion turbines should not set the proxy price, because they do not have the flexibility to be dispatched on a 10-minute basis. The Commission's mitigation plan is based on the payment of the marginal

cost of the last generator dispatched to serve the last increment of load. Therefore, if a combustion turbine is the last generator dispatched, its bid should establish the market clearing price.

2. Calculation of Market Clearing Price

Rehearing requests raise a number of issues with respect to the calculation of the mitigated price, particularly with respect to the gas prices and emission prices used.

a. Gas Costs

Under the Commission's April 26, 2001 approach, gas costs used in the formula are determined by an average of reported daily spot gas prices at California delivery points. The requests for rehearing raise a number of issues regarding the use of gas costs to determine the market clearing price. Several rehearing requests contend that the Commission should not use proxy prices, but should use actual gas (and emissions) costs for generators.[54] Others contend that using the reported gas prices overstates gas costs, because generators have a portfolio of gas supplies and are not buying all their gas at spot prices.[55] The ISO and CEOB contend that to better reflect supply

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[54] Rehearing Requests by NCPA, Seattle, Edison.

[55] Rehearing Requests by ISO, CPUC, Assembly, Metropolitan, PG&E, SDG&E, San Diego, San Francisco, Edison.

portfolios, the Commission should use monthly bid-week gas prices, rather than daily spot prices. The ISO recommends the Commission use bid-week monthly prices from Gas Daily, but for only three points in California, Malin, SoCal Gas (large packages), and PG&E city-gate (excluding PG&E large packages). Others contend that using the average gas price does not accurately reflect the marginal costs of generators, because as prices are higher at the Southern California points than Northern California points.[56] They suggest that the gas proxy price should be revised to more accurately reflect the marginal costs of each generator.

The Commission's mitigation plan is designed to establish generators' bids and market prices up-front. Using actual costs to determine marginal cost, as some suggest, would not establish generator bids, but would require an after-the-fact review of whether a generator's bid actually reflected its marginal cost. Using actual costs, therefore, would not provide price transparency, and would be administratively infeasible because it would require a constant reevaluation of every generator's bids.

The Commission will revise the spot gas prices to be used in the formula to accord with the requests by the ISO to establish the proxy gas cost for

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[56] Rehearing Requests by CEOB, Dynegy, Reliant, Williams.

determining marginal costs.[57] The ISO will be required to average the mid-point of the monthly bid-week prices reported by Gas Daily for three spot market prices reported for California.[58] This price represents a reasonable proxy for the marginal cost that generators will incur, since they can pre-buy their gas requirements for the month at this price.[59]

The Commission recognizes that, as Reliant and Dynegy point out, spot gas prices in southern California off of SoCal Gas's system exceed other spot prices in California. The staff of the California Energy Commission has recognized that a chief contributor to the high natural gas prices in southern California is the deficit of intrastate capacity on the SoCal Gas system.[60] It reports that the interstate delivery capability exceeds the ability of SoCal Gas to receive that gas by 300 MMcf/d. It concludes that:

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[57] *See* Norwood v. FERC, 962 F.2d 20, 22 (D.C. Cir. 1992) (one of the best established principles of classical economics: social welfare is maximized when the marginal cost of purchasing any commodity is equal to the marginal cost of producing it); Electricity Consumers Resources Council v. FERC, 747 F.2d 1511 (D.C. Cir. 1984).

[58] The three points are SoCal Gas (large packages), Malin, and PG&E city-gate.

[59] The average for June as reported in the Gas Daily Price Guide is $9.10. The bid-week monthly index prices are SoCal Gas (large packages) $11.71, Malin $5.98, PG&E Citygate $9.61.

[60] California Energy Commission Staff Draft Report, Natural Gas Infrastructure Issues, Docket No. 00-CEO-Vol -I, at 43 (May 17, 2001).

> this deficit in receipt capacity contributes to the high natural gas prices in California and the tight supplies to meet natural gas demand by electric generators.[61]

Another contributing factor to the high gas prices is the inability of generators and other shippers to acquire firm transportation rights on SoCal Gas's backbone system and SoCal Gas's system of allocating transportation on its backbone system, which leads to great uncertainty in scheduling gas supplies from interconnecting pipelines. This Commission recently has taken action to help improve the certainty of nominations on interstate pipelines into southern California,[62] but in the absence of scheduling changes on SoCal Gas, the Commission's changes to interstate scheduling practices cannot remove this uncertainty altogether. The Commission staff held a technical conference on May 24, 2001 to examine the problems in California gas infrastructure in which many participants continued to express concern about the lack of intrastate capacity on SoCal Gas and the difficulty in achieving certainty in scheduling gas supplies due to SoCal Gas's allocation

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[61] California Energy Commission Staff Draft Report, Natural Gas Infrastructure Issues, Docket No. 00-CEO-Vol -I, at 43 (May 17, 2001).

[62] Amoco Energy Trading Corp. v. El Paso Natural Gas Company, 93 FERC ¶ 61,060 (2000), *aff'd* 94 FERC ¶ 61,225 (2001).

procedures.[63] The Commission also is continuing to pursue efforts to try to dampen these higher prices into southern California. For example, the Commission recently issued orders requesting comment on whether to establish reporting requirements to create greater transparency in the gas market for southern California and whether imposing a price ceiling on capacity release transactions would have an effect on dampening prices.[64] The Commission will continue to monitor the situation in California to see whether further efforts are needed.

In addition to the dysfunction in southern California gas markets, the Commission cannot be certain that the daily SoCal Gas (large packages) spot price represents the actual cost of southern California generators. Gas Daily and the other reporting services do not indicate what volume moves at these prices, how much volume may be sold at lower prices in non-spot markets, and whether generators may be able to use other options to protect themselves against such higher prices.

Because of these concerns about the supplies coming into California from SoCal Gas, the Commission

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[63] California Natural Gas Transportation Infrastructure, Docket No. PL01-4-000.

[64] Order Proposing Reporting Requirement on Natural Gas Sales to California Market and Requesting Comments, 95 FERC ¶ 61,262 (2001); San Diego Gas & Electric Company, *et al.*, 95 FERC ¶ 61,264 (2001).

does not find it reasonable to base the market clearing energy price for California and the remainder of the WSCC solely on the southern California spot price for gas. Instead, the most equitable way of handling this issue is to use the approach described above. Under the mitigation plan adopted in this order, individual southern California generators are permitted to justify bids above the market clearing price so long as they can show their entire gas portfolio justifies such a bid.

b. Emission Costs

The April 26 Order stated that the emission cost would be calculated by the ISO using emissions costs from Cantor Fitzgerald Environmental Brokerage Services and the emissions rate for each unit. Many rehearing requests point out that the method of paying for exceeding emission allowances has been changed, so generators no longer can buy NOx emissions when they run out of emission allowances. Instead, local air districts now require generators to pay mitigation fees when they exceed their emission allowances.

Several rehearing requests contend that the emissions cost should not be included as part of the proxy price, but should instead be collected in an uplift charge when actually incurred.[65] Several also

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[65] Rehearing Requests by ISO, ARB, CEOB, CPUC, Assembly, PG&E, San Diego, SCAQMD, Edison, SCWC.

argue that not all generators pay emission costs and those that do incur such costs pay them only when they have used up their emission allotments.[66] They contend, therefore, that emissions costs should not be included until they have to be paid. ARB maintains that mitigation fees are not variable costs and should not be included in the marginal cost calculation because it will increase prices to all customers. It also argues that including mitigation fees as part of marginal costs will result in increased pollution as air districts may decide to reduce the emissions fees as a result of the higher consumer costs for power.

Sellers, on the other hand, contend that emissions costs are legitimately included as marginal costs.[67] They maintain that in running beyond their allotment of emission costs today, they not only are required to pay mitigation fees, but their emission allotments in subsequent years are reduced.[68] Sellers claim they need reimbursement for the opportunity costs of losing the ability to run their units in later years.

We will eliminate NOx costs from the calculation of the mitigated market clearing price. Since the Commission issued the April 26 Order, the SCAQMD's RTC program for electric generators larger than 50 MW (which was publicly traded by Cantor Fitzgerald

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[66] Rehearing Requests by Assembly, PG&E, Edison, SCWC.

[67] Rehearing Request by Williams.

[68] Rehearing Requests by Dynegy, Mirant, Reliant.

Environmental Brokerage Services) has been eliminated by the SCAQMD's governing board and the rules governing generator run-times have been altered by the Governor of California.[69] There are 35 air quality districts within California and many of these districts treat NOx emissions differently from other air quality districts within California. Moreover, the ability of these districts and the state to change the rules governing NOx emissions renders a one size fits all approach for emission costs impractical.

However, mitigation fees associated with NOx emissions are a legitimate cost of producing energy. Therefore, generators should be permitted to recover the cost of these mitigation fees. We direct the ISO to develop a specific emission allowance administrative charge assessed against all in-state load served on the ISO's transmission system in order to recover NOx emission mitigation costs assessed against generators that are required to run in accordance with ISO dispatch instructions and the must offer provisions of this order. Monies collected through this administrative charge will be placed in an interest bearing escrow account by the ISO. When a generator actually incurs mitigation costs, the generator will submit an invoice to the ISO for recovery of these costs and the ISO must pay these invoices. Because

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[69] *See* Executive Order D-40-01 by the Governor of the State of California.

all customers within California benefit from cleaner air as a result of application of these mitigation fees, the administrative charge should be assessed against all in-state load served on the ISO's system. We direct the ISO to submit tariff modifications incorporating an emission allowance administrative charge within fifteen days of the date of the order.

c. O&M Adder

The April 26 Order added $2.00 to the marginal cost price for each generator to represent operations and maintenance (O&M) expense. MID and the Assembly claim the Commission has not justified the $2.00 adder for O&M expenses. MID maintains the Commission should permit generators to include actual O&M costs.

Variable O&M costs are legitimate marginal costs that are incurred as a result of the physical production of energy. Therefore, an adder to the marginal price of energy is appropriate in order for the generating unit to recover its variable O&M costs associated with each MWh produced and bid into the ISO's imbalance energy market. The Commission found in *San Diego Gas & Electric Company, et al.*, 94 FERC ¶ 61,245 (March 9 Order), that a $2/MWh adder for variable O&M expense was reasonable. Furthermore, in the March 9 Order, we noted that the California Energy Commission also estimates variable O&M expenses of $2 to $3/MWh in a recent

report titled "Market Clearing Prices Under Alternative Resources Scenarios 2000 to 2010."[70]

We are cognizant of the concerns raised by MID that the O&M adder may be lower than actual O&M expenses; therefore, we will increase the O&M adder from $2/MWh to $6/MWh. The O&M forecasts made by the California Energy Commission are for new, efficient combined cycle units that are not the units on the margin in the California market. An O&M adder of $6/MWh is based upon a seventeen year average of actual non-fuel O&M expenses for oil and gas-fired steam plants.[71] The California market primarily consists of older oil and gas-fired steam plants. Thus, using a long-term average of actual O&M expenses for the same kind of units currently in the California market should permit generators in the California market full recovery of all non-fuel expenses.

d. Heat Rate

The April 26 Order provided that the heat rate should be based on operational heat rates and should not include start-up and minimum fuel load costs. This requirement was justified because the market clearing price should reflect the costs needed to

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[70] 94 FERC at 61,863, n. 8.

[71] *See* http:/www.eia.doe.gov/oiaf/issues/opctbl3.html. Oil and Gas Steam Plant Operations and Maintenance Costs, 1981-1997.

operate at or near maximum output. Williams maintains that the bid for each generator should include minimum fuel and start-up costs. It also maintains the price should be calculated each hour based on the heat rate and NOx curves for the point at which the unit is dispatched.

On May 18, 2001, the ISO submitted a status report informing the Commission that the ISO had issued two market notices to market participants providing a format for submission of the requested heat and emissions data. The ISO requested heat and emission rates for eleven different operating points with the first and last operating points representing the unit's minimum and maximum operating level, respectively. As noted by the ISO, by collecting eleven different operating points, the ISO will be able to approximate the actual incremental cost curve of each generating unit and thereby develop representative proxy prices for each unit throughout the unit's operating range.

The ISO's proposal to include the minimum and maximum operating levels for each unit and nine points in between is reasonable. The ISO's heat rate curve reflects the minimum fuel load requirements requested by Williams. In addition, because the ISO will have the approximate heat rate curve for each unit, the ISO is directed to calculate the proxy market clearing price based upon the approximate point on the heat rate curve at which the last unit is

dispatched.[72] However, we will allow sellers to recover their actual start-up fuel costs. Sellers will invoice the ISO their actual start-up fuel costs for recovery by the ISO in the same manner that emissions costs are recovered, and the ISO must pay these invoices. We direct the ISO to submit tariff modifications incorporating these costs within 15 days of the date of this order. This change adequately reflects the concerns raised by Williams, and, therefore, its rehearing request is moot.

e. Opportunity Cost, Scarcity Rents, Recovery of Fixed Costs, and Justification of Higher Prices

Generators maintain that the Commission's methodology for calculating marginal costs excludes legitimate opportunity costs related to energy-limited plants as well as scarcity rents.[73] They further maintain that paying only marginal cost of the last unit dispatched will not provide them with a reasonable opportunity to recover the fixed costs of peaking units. They further maintain that they will be unable to recover legitimate scarcity rents.

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[72] The emissions data is no longer relevant based upon our aforementioned removal of NOx costs from the proxy market clearing price.

[73] Rehearing Requests by Avista, Duke Energy, Dynegy, Reliant, PPL.

As discussed previously, the Commission is permitting generators to fully recover their emissions costs. As the Commission explained in the April 26 Order, in the real-time market, generators do not have opportunities to sell in higher-price markets because the real-time market consists only of energy that has not been previously sold in bilateral transactions. Since the Commission is imposing similar mitigation over the United States western markets in this order, sellers would no longer have any incentive to offer energy at a higher price to any other buyers in other states. Further, by using the marginal cost of the last unit dispatched to establish the market clearing price during periods of reserve deficiency, the Commission is permitting all more efficient generators a fair opportunity to recover capital costs.

The generators maintain that, while the market clearing price will enable generators more efficient than the last generator dispatched to recover capital costs, it will not permit recovery of the capital costs for that generator. Sellers such as Avista, Duke Energy, Dynegy, Reliant, and PPL have a portfolio of generating capacity, with units that will be more efficient than the unit setting the market clearing price. Therefore, the amounts earned on the more efficient plants will cover the investment in the marginal plant. Furthermore, we note that California no longer relies exclusively on the spot market. Negotiated bilateral agreements have, in large part, replaced this market and provide opportunity for any seller to structure the arrangements necessary to

recover its costs. Finally, under the FPA and our authorization for market-based rates, sellers are not guaranteed to recover all costs but are provided the opportunity to do so.

The Commission, in this order, has sought to provide prices that emulate closely those that would result in a competitive market and that provide generators with a reasonable opportunity to recover their costs. Sellers have not suggested a reasonable method of measuring the magnitude of such costs. The Commission's mitigation plan uses available data to develop a reasonable marginal cost for each generator and to permit reasonable recovery of legitimate costs. If sellers do not believe that these prices sufficiently cover their costs, they can file for cost-of-service rates covering all of their generating units in the WSCC for the duration of the mitigation plan.

Reliant and PPL contend that generators are entitled to a premium to cover the real risk of non-payment in California. We recognize that the risk of nonpayment in California continues to be greater than that in the larger West Wide market. We also note that there is a longer payment lag in the ISO spot markets of approximately 75 days that does not generally exist in the Western bilateral spot markets. We instruct the ISO to add 10 percent to the market clearing price paid to generators for all prospective

sales in its markets to reflect credit uncertainty.[74] The adder is not instituted to compensate generators for past unpaid bills. The ISO must incorporate this provision in its compliance filing. This adder may be lifted by the Commission depending on the outcome of the settlement proceeding. However, the Commission believes that questionable business practices have sent negative signals to future supplies, credit rating agencies and investors and therefore an adder for credit risk is justified and necessary.

As described above, our order today prescribes a market-driven price mitigation mechanism in all hours. Sellers dissatisfied with these prices have two options. They may propose cost-based rates for their entire portfolio of generating facilities in the WSCC in a section 205 filing with cost support including a reasonable rate of return on investment that reflects the unique conditions in California. Alternatively, although we believe the mitigated price to be adequate, sellers can seek to justify each transaction above the mitigated price. Any such justifications, however, cannot include premiums to compensate for credit risk, since our market-clearing price for the ISO's markets already reflects an adder for this risk. Similarly, a seller's emission costs cannot be used to justify exceeding the market-clearing price because our order allows each seller to recover its emission

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[74] This adder will not be reflected in the market price for the rest of the WSCC.

costs directly from the ISO. Claims of opportunity costs will not be considered because energy that is available in real-time cannot be sold elsewhere. Also, as explained elsewhere, marketers will not be allowed to justify prices higher than the mitigated prices because they must be price takers. Finally, while our approach allows recovery of gas costs, we will consider justifications based on higher actual gas costs if conditions in natural gas markets change significantly (assuming, of course, that suppliers can document and support their gas purchasing portfolio and allocation among all generating units at the relevant time).[75]

3. Applicability to Marketers And Out-of-State Generators

A number of rehearing requests contend that generators can circumvent price mitigation by selling energy to marketers.[76] They argue the generator could sell energy to a marketer at a high price and then the marketer could bid a high price into the ISO market, which it justified on the basis of its acquisition cost. In order to ensure compliance with the price

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[75] Currently, emission costs outside of California are *de minimis*. However, we recognize that this may change, and that sellers could be subject to entirely new costs resulting from changes in circumstances. We will consider such costs on a case-by-case basis.

[76] Rehearing Requests by ISO, CEOB CMUA, Metropolitan, NCPA, SMUD, San Diego, Edison.

mitigation, the Commission will not permit marketers to bid a price higher than the market clearing price. This will still provide marketers with an opportunity to earn a reasonable return on purchased energy, since the mitigated price is established by the marginal costs of the last unit dispatched and this price will be above the costs of the generators from which the marketers obtain their portfolio of energy. In this case, the marketer is no different than the last generator dispatched; it can recover the marginal costs of the last unit of energy produced.

The ISO maintains that out-of-state generators should be covered by the mitigation requirement so that any bids they submit above the market clearing price will be subject to refund. Out-of-state generators that want to have their marginal costs included in calculating the market clearing price can submit the required heat rate and gas source to the ISO for use in calculating the market clearing price. In the April 26 Order, the Commission did not require out-of-state generators to justify their price if they bid into the ISO market, because the Commission did not want to discourage out-of-state generators from bidding into the ISO market. However, now that the Commission is implementing mitigation for the entire WSCC, out-of-state generators will be treated like in-state generators.

F. Conditions on Market-Based Rate Authority

The April 26 Order conditioned public utility sellers' market-based rates to ensure that they do not engage in certain anticompetitive behavior. Sellers violating these conditions would have their market-based rates subject to refund and possible revocation.

Several generators have requested rehearing of this aspect of the April 26 Order.[77] Mirant and Williams, for example, urge the Commission to realize that sellers save certain units for when they can get the best price. Mirant contends that the bidding practices proscribed by the April 26 Order are legitimate, justifiable strategies in a competitive market and requests the Commission to eliminate the conditions or at a minimum, to limit the imposition of the conditions to certain hours.

Dynegy opposes the prohibition on the first category of bids, so-called "hockey stick" bidding. Dynegy submits that the risk of outage goes up substantially as the unit is pressed into operating longer than is advisable. The generator, therefore, faces new risks, such as a forced outage, and must be able to place premiums on the price per unit. EPSA. meanwhile, opposes the prohibition on bids that rise as the unit's output drops. EPSA states that the Commission should not revoke market-based rate authority based on a legitimate effort to recover total

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[77] Rehearing Requests by Dynegy, Mirant, Reliant, EPSA, Duke, PPL.

costs, but rather only if it finds that market power has been abused.

We will not tolerate abuse of market power or anticompetitive bidding or behavior. Emblematic of these practices is the now well-publicized bid of $3,880/MWh by Duke Energy. This bid resulted in total revenues for Duke Energy of $11 million. Exacerbating the problem was the fact that, while this transaction was identified in the March 9 Order as exceeding the proxy price, Duke Energy failed to even report this transaction in its quarterly report. The March 9 Order gave Duke Energy the choice of refunding all revenues in excess of those that would have occurred using the proxy price, or justifying the higher bid. Duke Energy chose the latter. Duke Energy argued that the payments for the energy it had supplied were in arrears, and therefore, it added a credit premium. The data show that Duke Energy's risk premium exceeds its variable cost by an order of magnitude.[78] Duke Energy's bidding at multiples of its marginal costs in an attempt to recover past due amounts can in no way be found to be just and reasonable. Accordingly, Duke Energy is directed to refund with interest pursuant to 18 C.F.R. § 35.19a,

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[78] Duke Energy unequivocally states that it is using the $3,880/MWh bid as a negotiating tool to recover payment for prior transactions. Duke Energy states that it will settle for the proxy price if and when it is paid in full for its prior, unpaid transactions. March 23, 2001 compliance filing in Docket Nos. ER01-1448-003 and ER01-1448-004 at pp. 10-12.

or offset, down to the level of the proxy price, $273/MWh for January, during the relevant hours. As the proxy price is well above Duke Energy's claimed running costs, it will be sufficient to cover any credit risk that Duke Energy may face.[79]

Public utility sellers' market based rate authority will be subject to potential revocation if they are found to have engaged in inappropriate behavior. Further, WSCC public utility sellers' market-based rate authorizations are hereby conditioned on agreeing to potential refunds for overcharges resulting from anticompetitive behavior.

The Commission denies Dynegy's request asking the Commission to clarify that the prohibition on bidding practices will expire on April 30, 2002, along with the rest of the April 26 Order.

G. Refunds

In the April 26 Order, the Commission established that all charges below the market clearing price would not be subject to refund. Refunds would be required only for sellers that fail to justify bids above the market clearing price. The Commission further stated that generators would not be

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[79] The Commission notes that there are a number of submittals dealing with sellers' market-based rate authorizations as well as bid justifications. We will address them in separate orders, if not resolved as part of the settlement process established elsewhere in this order.

liable for refunds if the Commission did not act within 60 days of the filing of the justification report.

PG&E and Edison maintain that the Commission cannot erase statutory refund obligations by stating that certain prices are deemed just and reasonable. Edison argues that the Commission must order refunds for all amounts above a just and reasonable rate and should not be able to limit refunds to emergency situations. Edison maintains that the Commission cannot establish that refund authority will expire within 60 days. It further contends that the Commission cannot shield generators from refunds, because the Commission has the authority to correct its legal errors. The CPUC maintains that refunds should exceed unlawful gains to act as a deterrent and suggests that the Commission impose treble damages, as provided for in antitrust law.

The Commission is establishing price mitigation in all hours of reserve deficiency and, as a discretionary matter, is also extending a form of that mitigation to hours of non-reserve deficiency. This price mitigation establishes the maximum just and reasonable rates in spot markets, absent cost justification. Moreover, the 60 day period for review of cost justifications was a self-imposed requirement to ensure that there is price certainty. The Commission has the authority to extend the period if necessary to finish processing the justifications.

With respect to the CPUC's arguments, the CPUC cites no provision of the FPA authorizing the

Commission to impose penalties. Finally, the Commission has no authority to impose treble damages.

H. Underscheduling Penalty

On December 15, 2000, the Commission issued an order which established, among other things, as part of a comprehensive price mitigation plan, a maximum penalty of $100/MWh if energy buyers had over 5 percent of their load served in the real-time market.[80] Several parties request that the Commission suspend the penalty for underscheduling in this proceeding.[81] Due to the Commission's decision in the April 26 Order to defer action on suspending the penalty for underscheduling, we will address this issue in a future order.

I. Confidentiality of Data

The Commission stated in the April 26 Order that it would continue the previous practice of keeping bid data confidential for six months, because disclosure of such information may lead to a reduction in competition because it will allow competitors to learn what their competitors are bidding and could lead to price collusion or coordination. The Commission also found that generator's heat rates

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[80] San Diego Gas & Electric Company, *et al.*, 93 FERC ¶ 61,294 (2000), *reh'g pending*.

[81] *See* Comments by CPUC, DWR, PG&E.

and emission cost information was also confidential business information that should not be disclosed.

Several parties contend that the Commission should not keep the heat rate and other cost information used to justify bids confidential, but should make the data publicly available, under section 205 of the FPA, on a next-day basis.[82] They also assert that due process requires that all data used to determine the proxy price is an essential part of a rate schedule and must be made available so it can be challenged by other parties, particularly ratepayers. SCWC and Assembly contend that the solution to collusion or gaming is not confidentiality, but rather regulation of seller conduct. As an alternative, San Francisco and Assembly maintain that the Commission can keep the data confidential, but that the filing of the data should be publicly noticed pursuant to the FPA, and the data should be available for review by those parties who enter into a protective order.

As the Commission found in the April 26 Order, the information on heat rates and emission costs is highly confidential business information. The disclosure of such information can cause competitive harm by allowing competitors to learn of the behavior and costs of their competitors. The Commission regulations provide for granting confidential treatment of

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[82] Rehearing Requests by NCPA, Assembly, SCWC, Edison, San Francisco, PG&E.

business sensitive information.[83] These issues are raised in other pleadings before the Commission, and we will address these matters in a later order.

EPSA's concerns relate to the independence of the ISO Board and the apprehension of disclosing confidential data to a non-independent body. EPSA suggests replacing the ISO Board or alternatively, requiring the reporting of such data to an independent entity so it can perform the marginal cost calculations. The concerns related to the independence of the ISO Board are beyond the scope of this rehearing and will be addressed in a later order.

M-S-R and TANC state that the April 26 Order is silent with respect to ordering the ISO to keep the bid and cost data confidential. While the Commission finds that the order was sufficiently clear in the first instance, out of an abundance of caution, the Commission clarifies that the ISO is ordered to treat all cost data in a confidential manner.

J. Review and Duration of the Mitigation Plan

In the April 26 Order, the Commission established a maximum one-year time period for the duration of the mitigation plan. In addition, the Commission instituted a process for reviewing the

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[83] *See* 18 C.F.R. §§ 388.112 (2000), 385.206(e), 385.213(c)(5), 385.410(c) (providing for confidential treatment for business sensitive information).

operations of the plan and the conditions in the California market on a quarterly basis.

Several parties request rehearing on the duration of the mitigation plan, stating that the Commission's decision to establish a pre-determined time period for applying mitigation is arbitrary and capricious.[84] Anaheim asserts that there is no rational basis for ending the mitigation after one year while SCWC states that the only criterion for terminating mitigation is whether markets are competitive or not. Metropolitan states that the Commission's assumptions about planned demand reduction and market development within one year should not be the basis for terminating mitigation. Metropolitan, Assembly, and others urge the Commission to monitor the progress of market entry by new generation and other market developments before termination.

The Commission is requiring the ISO to file on or before March 26, 2002, a report on market conditions that addresses among other things: (1) a list of all new generating resources (including the nameplate capacity) that the State of California has announced this year would be on line by summer 2002 and which of those facilities actually are on line (see Attachment to this order);[85] and (2) the continued progress in

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[84] Rehearing Requests by Edison, CPUC, CMUA, Anaheim, SCWC, Metropolitan.

[85] As pointed out in the April 26 Order, California has committed itself to increasing in-state generation and projects that new generation totaling 4,168 MW will be on line by the

(Continued on following page)

executing long-term contracts and reducing the reliance on the spot market. We will extend the mitigation through September 30, 2002. Our requirement for quarterly reports will continue.

K. RTO Proposal

In the April 26 Order, the Commission conditioned the implementation of the market monitoring and mitigation plan on the ISO and the three investor-owned utilities (IOUs) (SDG&E, Edison, and PG&E) filing an RTO proposal by June 1, 2001, consistent with the characteristics and functions in Order No. 2000.

Several parties have requested rehearing challenging the Commission's conditioning mitigation on the filing of an RTO.[86] While requesting rehearing on the lawfulness of the condition, City of Seattle and others assert that filing an RTO proposal by June 1, 2001 is highly unrealistic, and therefore request that the RTO condition be removed from the April 26 Order on rehearing.

As noted in the April 26 Order, the RTO condition recognizes that the only real solution to supply problems that affect the Western United States is to

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end of August 2001 and that there could be as much as 6,879 MW on line for the summer of 2002.

[86] Rehearing Requests by Seattle, Anaheim, SCWC, San Diego, CPUC, PG&E, CMUA, Metropolitan, CEOB.

create a regional response. The Commission intended to create such a response, and to improve and enhance supply and deliverability infrastructure so as to make the deliverability of supply possible and more reliable by imposing this condition as a necessary component to a solution for California and the Western United States. The ISO and two IOUs, SDG&E and Edison, filed an RTO proposal on June 1, 2001. PG&E also made a separate filing. Since the RTO filings have been made, the monitoring and mitigation plan will remain in effect. The Commission will address the adequacy of these filings in future orders. Since the ISO and utilities made the requisite filings, the requests for rehearing on this issue are moot.

L. West-Wide 206 Implementation

In the April 26 Order, the Commission instituted an investigation under section 206 of the FPA into the rates, terms and conditions of sales for resale of electric energy in interstate commerce in the WSCC other than sales through the ISO's markets, to the extent that such sales for resale involve: (1) electric energy sold in real-time spot markets (*i.e.*, up to 24 hours in advance) and (2) take place during conditions when contingency reserves (as defined by the WSCC) for any control area fall below 7 percent. These proceedings were instituted to investigate whether and the extent to which significant increases in the prices for energy and ancillary services in the

California market are affecting prices for such services in the WSCC outside of California.

In the April 26 Order, the Commission recognized that the California market is integrated with those of other states in the WSCC. Therefore, the Commission stated its intention that, to the extent possible, its proposed changes would mirror the measures to be applied to California markets.[87] The April 26 Order proposed the following three measures for the WSCC:

> (1) A requirement that all public and non-public utility sellers, with energy operationally and contractually available in real-time, offer that energy for sale;
>
> (2) Price mitigation during periods when reserves fall below 7 percent; and
>
> (3) A condition on the market based rate authority of public utility sellers selling in the WSCC region to ensure that they do not engage in anti-competitive behavior.

On April 27, 2001, the Commission issued a notice establishing a refund effective date 60 days from the date on which notice of initiation of the investigation was published in the Federal Register. The notice was published in the Federal Register, 66 Fed. Reg. 22223, on May 3, 2001. Thus, the refund effective date is July 2, 2001.

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[87] 95 FERC ¶ 61,115, at 61,356.

1. WSCC Mitigation Plan Overview

Based upon the need for uniform pricing throughout the Western region, we now find it necessary to adopt a market monitoring and mitigation plan for the WSCC spot markets. This plan will consist of several primary elements, each of which is intended to closely mirror the monitoring and mitigation plan we have adopted for California while also taking into account the various disparities between the California and WSCC markets.

Effective on the day following the date of this order, the plan we adopt below applies in all hours to all spot market transactions througnout the WSCC. In the hours when California experiences reserve deficiencies, prices for WSCC spot market sales cannot exceed the ISO's hourly market clearing price, absent justification.

Under our current and revised mitigation plan, the price in the ISO's Imbalance Market during times of insufficient operating reserves will consistently reflect the marginal cost of energy. Recent data show that during hours of sufficient operating reserves, the average hourly Imbalance Energy price has been zero and at times a negative value. These prices indicate that either there were no transactions in this market or that generation actually exceeded load during these hours. While there may be a number of factors that contribute to these anomalous results (*e.g.* changes in buying strategies), we are convinced that

we must use a modified mitigation approach during hours of non-reserve deficiencies.

For spot market sales, both in the WSCC and in California, in all non-reserve deficiency hours (*i.e.*, when reserve levels in the ISO exceed 7%), we will adapt the use of these market clearing prices. Eighty-five percent (85%) of the highest ISO hourly market clearing price established during the hours when the last Stage 1 (not Stage 2 or 3) was in effect will, absent justification, serve as the maximum price for the subsequent period. For example, if the highest hourly market clearing price during a Stage 1 is $140/MWh, spot prices in all subsequent non-reserve deficiency hours beginning when Stage 1 is lifted can be no higher than $119/MWh (*i.e.* 85 percent of $140/MWh). Sellers through the ISO's single price auction will receive the hourly market clearing price, but that clearing price will not exceed $119/MWh. For example, if the market clears at $90/MWh all bidders in the ISO's auctions will receive $90/MWh for that hour. However, bids are limited to $119/MWh and, therefore, the clearing price during the period will never exceed $119/MWh. For sales outside the ISO's single price auctions (bilateral sales in California and the rest of the WSCC), sellers will receive the prices they negotiate up to the maximum price, in this example, up to $119/MWh. This maximum clearing price will remain in place until the next Stage 1 is declared and a new price is set. When that Stage 1 is lifted, 85% of the highest hourly market clearing price from that period will carry forward.

Third, the plan imposes a must-offer requirement for all hours upon sellers with the exception of hydroelectric resources and capacity needed to meet WSCC minimum operating reserve criteria for control areas. Fourth, the plan applies to all public utilities (including marketers) and non-public utilities who sell into Commission-regulated spot markets or use the interstate transmission grid subject to our jurisdiction. Market-based rate authorizations for public utilities are hereby conditioned upon adherence to this plan.

2. Interventions and Comments

In the April 26 Order, the Commission provided that comments should be submitted within ten days of the date of that order. Timely notices of intervention, motions to intervene and comments in the WSCC proceeding were filed by the entities listed in Appendix B.

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, notice: of intervention and timely, unopposed motions to intervene serve to make the intervenors listed in Appendix B parties to this proceeding. Given the early stage of the proceedings, we will accept the late-filed comments.

3. Megawatt Laundering

In the April 26 Order, the Commission noted that several commenters complained that generators may

avoid the Commission's mitigation requirements through "megawatt laundering." In that order, the Commission recognized that the California market is integrated with other states and instituted the instant investigation. In addition, the Commission extended the must-offer obligation to include non-public utility generators in California which currently make use of the ISO's interstate transmission grid. In their comments, CPUC, DWR, TURN/UCAN, and CEOB request that the Commission also address megawatt laundering in this proceeding.

As discussed above, megawatt laundering will no longer be a concern due to our revised mitigation plan. First, the mitigation plan will be for all hours and will be applicable uniformly throughout the WSCC. Second, both sales within and outside California will be treated uniformly including sales by marketers. As a result of these modifications, this strategy cannot be used to avoid potential mitigation.

4. The Proposed 7 Percent Reserve Deficiency Trigger

The April 26 Order established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, and proposed that mitigation in the WSCC would be triggered when contingency reserves (as defined by the WSCC) for any control area fall below 7 percent.

Numerous commenters raise issues regarding how the reserve deficiency mechanism would be implemented for the WSCC. Based on the numerous concerns raised by the comments, we will simplify the West-wide mitigation so that it will trigger only when the ISO declares a reserve deficiency.

5. The Proposed Must-Offer Requirement

In the April 26 Order, the Commission included a requirement that all generators in California (with the exception of hydroelectric power), including non-public utility generators that make sales through the ISO's markets or that use the ISO's interstate transmission grid, must offer any power that they have available in real time to the ISO. This includes power not already scheduled to run through bilateral agreements.[88] With respect to the WSCC investigation, the Commission stated that it intends to mirror the approach used in California.

A number of parties oppose the requirement for the WSCC. For example, the Oregon Office of Energy believes that a requirement to offer energy for sale is difficult to police because a generator must be allowed to decide when its equipment must be taken out of service and at what levels of output it can run.

We clarify that the must offer requirement throughout the WSCC will not apply to hydroelectric

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[88] 95 FERC ¶ 61,115, at 61,355-57.

resources or to generation that is necessary for control area operators to meet the applicable WSCC Minimum Operating Reserve Criteria. We recognize that outside of California there is currently no operational ISO or RTO in place in the WSCC and therefore, no centralized location to post this information. The lack of an operational regional structure will make implementation of this feature of the mitigation plan difficult.

In order to implement this feature of the mitigation plan immediately, we will require all public utilities that are control area operators to have their wholesale merchant function calculate on a daily basis the amount of capacity that will be available after load and operating reserve forecasts have been calculated. The wholesale merchant function will post this information on its company web site and on the Western System Power Pool (WSPP) web site, and will maintain in its daily log the amount of non-hydro resources that will be available. Actual arrangements for energy sales from such resources should be made with the wholesale merchant function and not with the control area operator.

To implement this requirement, we will require each marketer and independent power producing entity to post available capacity on a daily basis on its own web site and the WSPP web site.

6. Applicability to Non-public Utilities

The April 26 Order extended the must offer requirement and the price mitigation plan to non-public utility generators in California which currently make use of the ISO's interstate transmission grid or sell in the ISO's markets. The Commission found that extending these requirements to non-public utilities is necessary to ensure that the mitigation and monitoring proposal is applied equally to all generators in California.[89] Similarly, the April 26 Order proposes to extend these requirements to non-public utility generators in the WSCC.[90]

Non-public utilities oppose applying these requirements to them. On the other hand, Avista Energy requests that the Commission suspend price mitigation measures established for public utilities in the WSCC if the Commission does not extend the mitigation measures to non-public utility sellers.

For the same reasons the April 26 Order applied mitigation to all generators within California, we will extend the mitigation plan adopted herein to include all public and non-public utilities throughout the WSCC. Moreover, the percentage of non-public utility generation in the WSCC outside of California is significantly larger than that inside of California.[91]

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[89] *Id.* at 61,356.

[90] *Id.* at 61,365.

[91] *See* Powerdat database, Resource Data International, Inc., April 2001 data set.

We believe that all entities must assist with solving the problems in the WSCC. Accordingly, the Commission will require that, as a condition of selling into the markets which are subject to this Commission's exclusive jurisdiction, and as a condition of using Commission jurisdictional interstate transmission facilities, all sellers located in the WSCC, including non-public utility sellers in the WSCC, must abide by the WSCC price mitigation plan and by the must-offer obligation (if applicable) described in this order.

While the Commission does not directly regulate the non-public utility sales for resale throughout the WSCC, we have the authority, and, indeed, the responsibility, to ensure that rates, terms and conditions for jurisdictional service are just and reasonable. However, the Commission cannot ensure such just and reasonable rates in the current circumstances in the WSCC unless all entities that sell energy in the relevant spot markets or use the interstate transmission grid subject to our jurisdiction abide by the same conditions. Finally, by applying the plan discussed in this order to non-public utilities, we eliminate the incentive, and the means, for public utilities to avoid mitigation (*i.e.*, by making wholesale sales to non-public utilities for resale in the spot market).

7. Refund Issues

As noted above, the refund effective date established in this proceeding is July 2, 2001. Some

parties contend that it is premature to establish a refund effective date for the WSCC, or that the prospect of refunds could cloud supplier decision-making, while others are concerned that if a transaction is executed in the day-ahead market prior to a declared reserve deficiency, the transaction should be honored without mitigation or refund obligation.[92]

We will not rescind the refund effective date because we are legally obligated to establish a refund effective date when an investigation is instituted under section 206 of the FPA. We have established the earliest possible refund effective date permitted by the FPA Section 206, to provide maximum protection to customers. We expect that sellers will observe the requirements of this order and that the need for refunds will be rare. The commenters have not justified providing less protection. Moreover, the mitigation plan is taking effect prior to the refund effective date and this should obviate the need for refunds.

8. Mitigation Beyond Summer 2001

Although we are confident of the efficacy of our West-wide mitigation plan throughout the Summer of 2001, we nonetheless wish to obtain comment for the purpose of revising the mitigation methodology for

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[92] *See* Comments of Avista Energy, Duke and Powerex.

future periods, if necessary.[93] Accordingly, we invite interested partes to file with the Commission comments and proposals concerning: (1) any developments, either beneficial or adverse, which have occurred in the Western region spot markets as a result of this order; (2) any difficulties with implementation of the mitigation plan detailed in the order, and the relevant solutions thereto; and, most importantly (3) any alternative market mitigation approaches. In order to provide for timely review and analysis, we will require that parties' comments and proposals be submitted to the Commission within 60 days of the date of issuance of this order.

M. Settlement Conference

We will require that all public utility sellers and buyers in the ISO's markets participate in settlement discussions to complete the task of settling past accounts and structuring the new arrangements for California's energy future. To achieve this goal, it is imperative that the parties reach agreement on (1) the additional load that is to be moved from the spot market to longer-term contracts, (2) refund (offset) issues related to past periods, and (3) creditworthiness matters. In highlighting these specific issues, we are not suggesting that the settlement discussions

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[93] In particular, we seek comments on whether our approach is appropriate given regional differences between California and other regions.

are limited to these matters, but emphasize that all issues that remain outstanding to resolve past accounts and ensure California's energy future are on the table for the parties to address. Finally, we stress that it will be critical to the success of these discussions that the State of California designate one or more representatives, authorized to act on behalf of all affected state interests, to participate fully in the settlement discussions. We will appoint the Chief Administrative Law Judge or his designee to serve as a settlement judge to assist the parties in reaching a settlement and require the judge to convene an initial settlement conference no later than June 25, 2001, and to complete the settlement discussions no later than 15 days after the commencement of the settlement conference. The settlement judge shall make a recommendation to the Commission within 7 days after the close of the settlement discussions if the issues are not resolved by the parties.

N. ISO Compliance Filing

In the April 26 Order, the Commission directed the ISO to submit a compliance filing no later than fifteen days from the date of that order. The ISO made its compliance filing in Docket Nos. EL00-95-034 and EL00-98-033 on May 11, 2001. Due to the significant modifications to the mitigation plan we are adopting today, we will require a new compliance filing within 15 days of the date of this order.

The Commission orders:

(A) The ISO shall submit tariff changes to comply with this order within 15 days of the date of this order.

(B) Sellers of energy in the WSCC are subject to the mitigation plan as discussed in the body of this order. The mitigation plan will become effective on the day following the date of this order.

(C) Rehearing is granted in part, and denied in part, as discussed in the body of this order.

(D) The requests for stays of the April 26 Order are denied as discussed in the body of the order.

(E) No later than 7 days after the completion of settlement discussions, the settlement judge shall make a recommendation to the Commission with respect to the settlement negotiations in the captioned dockets.

(F) Duke Energy must file a report quantifying refunds or offsets within 15 days of the date of this order, as discussed in the body of this order.

(G) Interested parties are hereby invited to file comments and proposals regarding the market mitigation plan, as discussed in the body of this order.

By the Commission. Commissioner Massey concurred in part with a separate statement attached.

(SEAL) Commissioner Breathitt concurred with a separate statement attached.

/s/ Linwood A. Watson, Jr.
Linwood A. Watson, Jr.,
Acting Secretary.

Appendix A
Requests for Rehearing of April 26 Order
(* – denotes request for late intervention)

Party	Abbreviation
American Public Power Association	APPA
Automated Power Exchange	APX
Avista Energy, Inc.	Avista Energy
California Air Resources Board*	ARB
California Department of Water Resources	DWR
California Electricity Oversight Board	CEOB
California Independent System Operator Corporation	ISO

California Municipal Utility Association	CMUA
California State Assembly	Assembly
Calpine Corporation	Calpine
Cities of Anaheim, *et al.*	Anaheim
City and County of San Francisco	San Francisco
City of Burbank*	Burbank
City of San Diego	San Diego
City of Seattle	Seattle
Cogeneration Association of California and Energy Producers and Users Coalition[94]	CAC/EPUC
Consumer Federation of America*	CFA
Duke Energy North America, *et al.*, LLC	Duke Energy
Dynegy Power Marketing, Inc. *et al.*	Dynegy
Electric Power Supply Association	EPSA
Imperial Irrigation District*	IID
Los Angeles Department of Water and Power	LADWP

[94] Request for stay.

M-S-R Public Power Agency, *et al.*	M-S-R
Metropolitan Water District of Southern California	Metropolitan
Mirant America's Energy Marketing, LP, *et al.*	Mirant
Modesto Irrigation District	MID
National Rural Electric Cooperative Association*	NRECA
Northern California Power Agency	NCPA
Pacific Gas and Electric Company	PG&E
PPL EnergyPlus, LLC, *et al.*	PPL
Public Utilities Commission of State of California	CPUC
Reliant Energy Power Generation, Inc.	Reliant
Sacramento Municipal Utility District	SMUD
San Diego Gas & Electric Co.	SDG&E
South Coast Air Quality Management District*	SCAQMD
Southern California Edison Company	Edison

Southern California Water Company	SCWC
Transmission Agency of Northern California	TANC
Turlock Irrigation District*	TID
Williams Energy Marketing & Trading Company	Williams

Appendix B
WSCC Comments
(* – denotes Motions to Intervene)
(** – denotes Notice of Intervention)
(*** – denotes late filed comments)

Party	Abbreviation
AES Southland, Inc.***	AES
American Public Power Association*	APPA
Attorney General of Washington*	Washington Attorney General
Automated Power Exchange	APX
Avista Energy, Inc.	Avista Energy
Avista Utilities	Avista Utilities
California Air Resources Board*	ARB
California Department of Water Resources*	DWR

California Electricity Oversight Board***	CEOB
California Independent System Operator Corporation	ISO
California Municipal Utility Association	CMUA
California State Assembly	Assembly
Cities of Anaheim, *et al.**	Anaheim
County of San Diego*	San Diego
City and County of San Francisco*	San Francisco
City of Burbank*	Burbank
City of Seattle	Seattle
Cogeneration Association of California and Energy Producers and Users Coalition*	CAC/EPUC
Cogeneration Coalition of Washington*	CCW
Colorado Association of Municipal Utilities*	Colorado AMPS
Duke Energy North America, *et al.*, LLC*	Duke Energy
Electric Power Supply Association	EPSA
Enron Power Marketing, Inc. and Coral Power, L.L.C.	Enron

Idaho Public Utilities Commission**	Idaho Commission
Imperial Irrigation District*	IID
Los Angeles Department of Water and Power***	LADWP
M-S-R Public Power Agency, *et al.*	M-S-R
Metropolitan Water District of Southern California	Metropolitan
Mirant America's Energy Marketing, LP, *et al.**	Mirant
Modesto Irrigation District*	MID
Morgan Stanley Capital Group Inc.	Morgan Stanley
National Rural Electric Cooperative Association*	NRECA
Nevada Attorney General's Bureau of Consumer Protection*	Nevada BCP
Nevada Independent Energy Coalition*	NIEC
Nevada Public Utilities Commission*	Nevada Commission
Northern California Power Agency	NCPA
NRG Power Marketing Inc.	NRG

Official Committee of Unsecured Creditors of PG&E*	OSC
Oregon Office of Energy	Oregon Office of Energy
Pacific Gas and Electric Company*	PG&E
Pinnacle West Capital Corporation, Arizona Public Service Company, Pinnacle West Energy Corporation and APS Energy Services, Inc.	Pinnacle West Companies
Portland General Electric Company	PGE
Powerex Corporation*	Powerex
PPL EnergyPlus, LLC, *et al.**	PPL
Public Utilities Commission of State of California**	CPUC
Puget Sound Energy, Inc.*	Puget Sound
Reliant Energy Power Generation, Inc.	Reliant
Sacramento Municipal Utility District	SMUD
Salt River Project Agricultural Improvement and Power District*	SRP
San Diego Gas & Electric Co.****	SDG&E

South Coast Air Quality Management District*	SCAQMD
Southern California Edison Company*	Edison
Tri-State Generation and Transmission Association, Inc.*	Tri-State
Turlock Irrigation District*	Turlock
Utah Municipal Power Agency*	UMPA
Utility Reform Network and the Utility Consumers' Action Network	TURN/UCAN
Washington Utilities and Transportation Commission**	Washington Commission
Williams Energy Marketing &Trading Company	Williams
Wyoming Public Service Commission***	Wyoming Commission

MASSEY, Commissioner, *concurring in part*:

Today's order brings expanded price restraints mitigation to a broken market. I support the order because it adopts measures that I have been championing for the past eight months. Price controls are now extended to the entire western interconnection, thereby eliminating the "megawatt laundering" problem that has vexed the mitigation programs

adopted by the Commission and the ISO over the past year. Cost-based price constraints are now extended to all hours, not just those of reserve deficiency. We have long needed 24 x 7 coverage, and now we finally have it. The price caps will remain in place until September 2002, giving the market two full summers to correct. I endorse these measures.

While better late than never, I wish this Commission had taken effective action sooner. Until today, the Commission had stubbornly refused to implement full time price constraints, despite rather clear evidence that prices were not just and reasonable. We could have prevented much of the economic carnage in the western interconnection that has occurred over the past year.

Given that the Commission today adopts measures that I have long advocated, I am tempted to declare victory and let it be. But I cannot. There are some aspects of the order that I have reservations about, and for these reasons I concur with the order. One aspect is the addition of a 10 percent surcharge to the market clearing price to reflect credit uncertainty. I do not see the need for this. The Commission has issued orders in the past few months instructing the ISO to abide by the creditworthiness requirements of its tariff. I am concerned that the adder may diminish the ISO's enforcement of those requirements. Moreover, it is my understanding that recently all sales into the ISO's markets have been backed by a creditworthy party. Instituting this surcharge does have a modest bright side, however.

Generators may no longer attempt to justify bids on the basis of credit risk above what is provided for in the cost based clearing pricing methodology. This was a major flaw of the old ineffective $150 benchmark in our earlier mitigation program. Eliminating that ground for high prices is a positive development.

Second, the order should have provided guidance to the parties that will participate in the settlement conference we order. I believe we are avoiding our responsibility under the Federal Power Act to set just and reasonable prices by requiring parties to settle a multitude of issues with a price tag in the billions of dollars without at least two cents worth of guidance.

And finally, I do not agree with the rhetoric in this order that characterizes cost of service pricing as irrelevant, and perhaps even downright harmful, on the theory that it would discourage new supply. I do not understand the need nor the logic of this language. We have made a choice in this order to strike a balance between strict cost of service regulation and blind reliance on the market. The mitigation program puts in place important cost based price caps while relying on market based pricing. The order sets out reasons for this balanced choice, and articulating them is all that is needed to support our decision. I strongly disagree with the statement in the order that "a cost-based inquiry alone would not be sufficient in these circumstances to fulfill the statutory duty" under the Federal Power Act. I do not read the Federal Power Act, and the relevant court decisions, so restrictively. There is still

an important role for cost of service regulation where markets are not adequate.

What is curious about this aspect of the order is that the concern is to avoid discouraging new supply. However, as the well respected economist Alfred Kahn recently said of our long reliance on cost of service regulation, "(i)f the literature agrees on anything about that experience, it is that cost-based regulation, as traditionally practiced, has encouraged the goldplating of service and the very excess capacity that seemed to promise such enormous benefits to consumers during the past decade if rates were deregulated."[1] Dr. Kahn believes that cost of service may lead to too much supply. Thus, I do not understand the majority's logic concerning cost-based regulation and supply adequacy.

These concerns notwithstanding, I support today's order and the price protection plan it puts in place. To ensure that this price protection plan is successful, the Commission must exercise all of its statutory powers to keep natural gas prices in the West at just and reasonable levels. It is probably generally true that the marginal plant dispatched in California is fired by natural gas and uses a lot of it. Thus, the success of the plan we adopt today in lowering prices depends in large part on fluctuations

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[1] Statement of Alfred E. Kahn before the Committee on Governmental Affairs, United States Senate, June 13, 2001 at page 3.

in the price of natural gas. The Commission continues to have work to do in ensuring just and reasonable gas prices.

Today's price protection plan gives California and the West breathing room while their electricity markets are brought back to health. A number of items need to be addressed in the next 15 months for the recuperation to be successful. Clearly, there must be substantial amounts of new generation capacity brought on line. A more balanced supply portfolio must be developed as California moves away from an over reliance on the spot markets. A robust demand response program must be implemented through demand bidding and accurate price signals. Transmission constraints must be relieved in some way. And finally, the California ISO should explore a number of market reforms, such as the adoption of security constrained unit commitment dispatch, the creation of an installed capacity market and reserve requirements, and a single integrated day-ahead market. Without these measures, I would be concerned about whether the markets in the West can be brought back to health.

For these reasons, I concur with today's order.

/s/ William L. Massey
William L. Massey
Commissioner

Breathitt, Commissioner, *concurring*;

I concur with the result of today's order, and write separately to highlight one aspect of it. I am concerned about the imposition of a ten percent surcharge on the market clearing price paid to generators to reflect credit uncertainty in California. I have two primary concerns. First, the imposition of such a credit surcharge seems to concede to the California Independent System Operator (ISO) the issue of whether or not the ISO must implement the Commission's creditworthiness standards. We have directed the ISO to ensure the presence of a creditworthy counterparty for certain transactions.[1] I am not ready to concede this issue and, therefore, I call upon the ISO immediately to implement our orders regarding creditworthiness.

Second, I believe the imposition of such a credit surcharge may be premature. In today's order we also initiate settlement discussions among all public utility sellers and buyers in the ISO markets. Among the issues we direct the parties to consider in their negotiations are "creditworthiness matters." I am concerned that the credit surcharge could adversely affect the settlement discussions on the issue of prospective credit uncertainty.

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[1] California Independent System Operator Corporation, *et al.*, 95 FERC ¶ 61,026, at 61,081 (2001)

Otherwise, I agree with my colleagues that creditworthiness and non-payment of accounts are serious problems in California. I believe the Commission and the ISO must take immeditate steps to address these problems. I just hope this surcharge does not prove to be an inappropriate remedy for this problem. Therefore, I respectfully concur.

/s/ Linda K. Breathitt
Linda K. Breathitt
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

101 FERC § 61,304

Before Commissioners:
Pat Wood III, Chairman;
William L. Massey, and
Nora Mead Brownell.

Puget Sound Energy, Inc., *et al.* Complainant,	)	
v.	)	
All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement, Respondents.	)	Docket Nos. EL01-10-000 EL01-10-001

ORDER ON MOTIONS TO
REOPEN EVIDENTIARY RECORD

(Issued December 19, 2002)

1. In this order, we grant in part and deny in part motions seeking to reopen the evidentiary record in the EL01-10, *et al.* docket for the purpose of allowing parties to submit additional evidence concerning potential refunds for spot market bilateral sales transactions in the Pacific Northwest for the period January 1, 2000 through June 20, 2001. In taking this action, our goal is to provide all parties an opportunity to ensure that all relevant evidence is

adduced in this proceeding, but also to bring closure and certainty to this proceeding (to sellers and customers alike) fairly and quickly.

I. Background

2. On October 26, 2000, Puget Sound Energy, Inc. (Puget Sound) filed a complaint alleging that spot market prices in the Pacific Northwest were unjust and unreasonable. In a December 15, 2000 order (December 15 Order),[1] the Commission declined to implement a region-wide price cap, as Puget Sound had requested. Puget Sound and others timely sought rehearing of the December 15 Order's determination not to impose a regional price cap or other mitigation. However, on June 22, 2001, Puget Sound filed a motion to dismiss its complaint and its subsequent rehearing request. Instead, in a July 25, 2001 order (July 25 Order)[2], the Commission established a preliminary evidentiary hearing pertaining to the Northwest for the period beginning December 25, 2000 through June 20, 2001 to help facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest. In the July 25 Order, the Commission also stated that it would

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[1] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, *et al.*, 93 FERC ¶ 61,294 (2000), *reh'g denied*, 97 FERC ¶ 61,275 (2001).

[2] San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, *et al.*, 96 FERC ¶ 61,120 (2001).

decide at a later time whether to allow Puget Sound to withdraw the complaint. On September 24, 2001, the Presiding Administrative Law Judge (ALJ) issued recommendations and proposed findings of fact in the case, finding no basis to order refunds.[3]

Motions

3. On May 13, 2002, the City of Tacoma, Washington (Tacoma) filed a motion in which it requests that the Commission reopen the evidentiary record in the EL01-10, *et al.* docket to allow a "hearing on all issues related to refunds for wholesale energy transactions in excess of the market clearing price in the Pacific Northwest" and permit further investigation and discovery into the actions of specific participants in the Pacific Northwest power market. Tacoma states that since the issuance of *Puget Sound,* material evidence has become available that demonstrates that the Presiding Judge's conclusions in that decision are "clearly erroneous." On September 9, 2002 and October 2, 2002, Tacoma filed supplements to its motion in which it identifies the existence of additional evidence it alleges is material and relevant to this proceeding.

4. In its motion, Tacoma identifies multiple grounds for reopening the evidentiary record in Docket No. EL01-10, *et al.* Among those are: (1) the release of

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[3] *See* Puget Sound Energy Company v. Sellers of Energy and Ancillary Services, 96 FERC ¶ 63,044 (2001) (*Puget Sound*).

documents obtained as part of the Staff investigation in Docket No. PA02-2-000; (2) the issuance of the Commission Staff's initial report in that docket, (3) the initiation of separate proceedings to investigate instances of possible misconduct of the companies named in those proceedings, which are also respondents in the EL01-10, *et al* docket; and (4) the Commission solicitation of comments on whether the Commission should change the method for determining refunds in the California refund proceedings. Tacoma also argues that the expedited nature of the proceedings that the Commission ordered contributed to material evidence being unavailable to the Presiding Judge in the EL01-10, *et al.* docket hearing. Tacoma also adds that the recommendations of the Presiding Judge in this proceeding are inconsistent with the determination the Commission made in Docket No. EL02-28, *et al.*,[4] setting for hearing the issue of whether the dysfunctional California spot markets adversely affected the long-term bilateral markets. Tacoma concludes that its motion and supplements thereto provide sufficient evidence to warrant further investigation and discovery into the actions of Pacific Northwest market participants.

5. On May 24, 2002, the City of Seattle, Washington (Seattle) filed a motion requesting that it be allowed to supplement the record or, alternatively, that the

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[4] Nevada Power Co. and Sierra Pacific Power Co. v. Duke Energy Trading and Mktg, L.P., *et al.*, 99 FERC 61,047, *order on reh'g* 100 FERC ¶ 61,273 (2002), *reh'g pending*.

Commission reopen the evidentiary record to allow for a hearing before the Presiding Judge. On June 24, 2002, Public Utility District No. 1 of Grays Harbor County, Washington (Grays Harbor) also filed a motion in this proceeding, requesting that the Commission reopen the evidentiary record. In particular, Seattle and Grays Harbor seek to supplement the evidentiary record with evidence developed in the PA02-2-000 Staff investigation and related proceedings.

Answers In Support

6. California Parties[5] and Attorney General of Washington (Washington AG) support Tacoma's motion. In their opinion, the reasons offered by Tacoma for reopening the evidentiary record are compelling. In particular, Washington AG argues that the Presiding Judge's recommendations are undermined by evidence obtained in Docket PA02-2-000 and that Pacific Northwest utilities should be treated equally with the utilities that have claimed refunds in the EL00-95, *et al.* docket proceeding. Washington Utilities and Transportation Commission, the Oregon Office of Energy, and the Oregon Public Utilities Commission (jointly, Washington Commission) do not oppose Tacoma's motion but urge the Commission to reopen the

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[5] California Parties include the People of the State of California, *ex rel.* Bill Lockyer, Attorney General, and the California Electricity Oversight Board.

evidentiary record only for the purpose of investigating the facts and consequences of market manipulation and to focus its remedies, if any, only on wrongdoers. The Washington Commission would oppose imposition of refunds based on spot market transactions.

Answers in Opposition

7. Puget Sound argues that the evidentiary record should not be reopened because the overwhelming majority of market participants, including public power entities, opposed initiation of a wholesale refund proceeding in these dockets in the first place. The Indicated Marketers,[6] Transaction Finality Group (TFG),[7] and Mirant argue that the movants have failed to demonstrate the extraordinary circumstances necessary to reopen the evidentiary record

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[6] The Indicated Marketers include Mirant Americas Energy Marketing, L.P. (Mirant); TransAlta Energy Marketing (U.S.) Inc.; and Morgan Stanley Capital Group Inc.

[7] The TFG is composed of Alcoa, Inc.; Avista Energy, Inc.; Columbia Falls Aluminum Company, LLC; Coral Power, LLC; Duke Energy Trading and Marketing, L.L.C.; Edison Mission Marketing & Trading, Inc.; Exelon Corporation on behalf of Exelon Generation Company, LLC; PECO Energy Company and Commonwealth Edison Company; IDACORP Energy, L.P.; Pinnacle West Capital Corporation/Arizona Public Service Company; Portland General Electric Company; PPL Montana, LLC and PPL Energy Plus, LLC; Public Service Company of Colorado; Public Service Company of New Mexico; Puget Sound Energy, Inc.; Trans Canada Energy Ltd.; BP Energy Company; Powerex Corp.; and Sempra Energy Trading Corp. Powerex Corp supports and supplements the comments filed by the TFG.

in this proceeding, as required by Commission precedent.[8] Similarly, TransCanada Energy Ltd. (TransCanada) asserts that Tacoma's motion fails to provide appropriate justification for its request. In TFG's and Indicated Marketers' opinion, the movants should also have established a logical or factual nexus between alleged market manipulation in the California Independent System Operator and California Power Exchange markets and alleged dysfunctions in the Pacific Northwest markets. Eugene Water and Electric Board, Coral Power (Coral), and TFG argue that there is no purpose to reopening the *Puget Sound* docket prior to the completion of the Staff investigation in the PA02-2-000 docket. TFG believes that a different approach would create uncertainty.

Procedural Matters

8. On June 3, 2002, the Bonneville Power Administration (BPA) filed an untimely answer to Tacoma's May 13, 2002 motion. On June 7, 2002, Tacoma filed a motion to strike BPA's untimely answer. We will disallow BPA's answer pursuant to Rule 213(d) of the

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[8] The Indicated Marketers cite to Systems Energy Resources, Inc., 96 FERC ¶ 61,165, at 61, 736 (2001) (holding that the Commission's "general rule is that 'the record once closed will not be reopened' absent a demonstration that extraordinary circumstances outweigh the need for administrative finality."); CMS Midland, Inc., *et al.*, 56 FERC ¶ 61,361, 61,736 (1991) (stating that the requesting "party must demonstrate a change in circumstances that is more than just material – it must be a change that goes to the very heart of the case.").

Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(d) (2002).

9. On August 7, 2002, Grays Harbor filed an answer to the Indicated Marketers' answer. Answers to answers are generally not permitted pursuant to Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2002), unless otherwise permitted by the decisional authority. We are not persuaded to allow Grays Harbor's answer to the Indicated Marketers' answer.

Discussion

10. In their motions, Tacoma, Seattle, and Grays Harbor seek to reopen or, in the alternative, supplement, the evidentiary record in Docket No. EL01-10, *et al.* In particular, Tacoma requests permission to introduce evidence developed in the PA02-2-000 docket and related proceedings and to conduct further investigation and discovery into the actions of Pacific Northwest market participants.

11. We will allow the movants and other parties in this proceeding to conduct additional discovery for the period January 1, 2000 to June 20, 2001. This may include depositions, data requests, and any other appropriate form of discovery. Parties should not duplicate the discovery conducted in other Commission proceedings, but may submit evidence from those proceedings in their filings in this proceeding, to the extent relevant. We direct the Chief Administrative Law Judge to appoint an ALJ as a Discovery Master

to resolve any discovery-related disputes that may arise. To prevent disclosure of confidential information, the presiding judge may adopt a protective order, as appropriate.[9]

12. All of the parties will have until February 28, 2003 to submit directly to the Commission additional evidence concerning potential refunds for spot market bilateral sales transactions in the Pacific Northwest for the period January 1, 2000 through June 20, 2001 and proposed new and/or modified findings of fact. Parties must provide relevant documents and citations to the record to support any proposed substantive recommendations.

13. We intend to finalize the issues in this docket expeditiously. For this reason, we are not remanding this case to the Presiding Judge and will review additional evidence along with the Presiding Judge's recommendations in *Puget Sound*. Therefore, Tacoma's, Seattle's and Grays Harbor's motions are hereby granted in part and denied in part.

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[9] The Commission and its Staff conducting the investigation in Docket No. PA2-2-000 will not be subject to discovery and the parties may not conduct depositions of and/or request information from the Commission or its Staff, as it would interfere with the Staff investigation in Docket No. PA02-2-000. The Commission's Litigation Staff shall not conduct discovery or otherwise participate in this phase of this proceeding.

The Commission orders:

(A) Tacoma's, Seattle's and Grays Harbor's motions are hereby granted in part and denied in part, as discussed in the body of this order.

(B) No later than February 28, 2003, the parties in this proceeding shall submit directly to the Commission additional evidence and proposed new and/or modified findings of fact with specific citations to the record to support any proposed substantive recommendations.

(C) The Chief Administrative Law Judge is hereby directed and authorized to appoint an Administrative Law Judge as a Discovery Master within ten days (10) of the date of issuance of this order. The Discovery Master shall administer discovery and resolve any potential discovery disputes.

By the Commission. Commissioner Brownell dissenting with a separate statement attached.

(SEAL)

Linwood A. Watson, Jr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc. *et al.*	)	
	)	
v.	)	
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All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement	)	Docket Nos. EL01-10-000 EL01-10-001

(Issued December 19, 2002)

BROWNELL, Commissioner, *dissenting*

In today's order the majority re-opens the record in a case in which a Presiding Administrative Law Judge has already completed a hearing and issued Recommendations and Proposed Findings of Fact; and in which the complainant has moved to withdraw its complaint. Neither equity nor efficiency is served by re-opening the record in this proceeding.

Nora Mead Brownell
Commissioner